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KRISTIN K. MAYES
GARY PIERCE

AZ CORP COMMISSION
DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA CORPORATION COMMISSIONON.	DOCKET NO. G-04204A-06-0463 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Robert G. Gray (Utilities Division); Julie McNeely-Kirwan (Utilities Division); Ralph C. Smith (Consultant - Larkin & Associates, Inc.); David C. Parcell (Consultant – Technical Associates, Inc.); and George E. Wennerlyn (Consultant – Select Energy Consulting LLC) in the above-referenced matter.

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Arizona Corporation Commission
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Staff is providing several pages containing confidential information from George Wennerlyn to Administrative Law Judge Nodes, the Commissioners, their Executive Aides and to those parties who have entered into a Protective Agreement with UNS Gas, Inc.

RESPECTFULLY SUBMITTED this 9th day of February 2007.

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REDACTED

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

JULIE MCNEELY-KIRWAN

RALPH C. SMITH

DAVID C. PARCELL

GEORGE E. WENNERLYN

DOCKET NOS. G-04204A-06-0463

G-04204A-06-0013

&

G-04204A-05-0831

IN THE MATTER OF THE APPLICATION OF

UNS GAS, INC. FOR JUST AND REASONABLE

RATES AND CHARGES

FEBRUARY 9, 2007

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR JUST AND REASONABLE RATES AND CHARGES.)))))	DOCKET NOS. G-04204A-06-0463, G-04204A-06-0013, G-04204A-06-0831

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

PUBLIC UTILITIES ANALYST 5

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

February 9, 2007

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ATTACHMENTS

EXECUTIVE SUMMARY
UNS GAS INC.
DOCKET NOS. G-04204A-06-0463 ET AL

My testimony in this proceeding addresses a number of issues related to UNS Gas Inc.' ("UNS") purchased gas adjustor ("PGA") mechanism. UNS has proposed to make a number of changes to the PGA mechanism and my testimony provides Staff's analysis and recommendations regarding the PGA mechanism.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am a Public Utility Analyst 5 employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utility Analyst 5.

A. In my capacity as a Public Utility Analyst 5, I conduct analysis and provide recommendations to the Commission on electricity and natural gas matters. A copy of my resume is attached as Exhibit RGG-1.

Q. What is the scope of this testimony?

A. This testimony will address UNS' PGA mechanism, including the base cost of gas, in this case.

Q. Have you reviewed the testimony of UNS Witness David Hutchins in regard to the PGA mechanism?

A. Yes. I have reviewed his testimony and will discuss his proposed changes to the PGA mechanism as part of my testimony.

BASE COST OF GAS

Q. Please discuss the use of a base cost of gas within the overall framework of setting natural gas rates.

A. The base cost of gas has traditionally been used as an estimate of the typical cost of natural gas to UNS and is included in UNS' base rates. The base cost of gas accounts for both the commodity cost and the cost of transporting the natural gas over the interstate pipeline system from its source to UNS' distribution system. UNS uses a PGA mechanism to account for the changing cost of natural gas. UNS currently uses a 12-month rolling average PGA mechanism, whereby a new PGA rate is calculated each month. Each month UNS calculates its average cost of natural gas, on a per therm basis, for the most recent 12 months. The monthly PGA rate is then derived by subtracting the base cost of gas from the 12-month average cost of gas. Therefore, over time, the PGA rate, the base cost of gas, and any temporary PGA surcharge/credit should reflect the total cost of natural gas for UNS. The PGA rate is banded, meaning that each new month when the new PGA rate is set it cannot be set at a rate that is more than $0.10 per therm different than the rate that was in place in any of the previous 12 months.

Q. How has the base cost of gas been dealt with in other recent natural gas rate cases?

A. In recent natural gas rate cases involving Southwest Gas and Duncan Rural Services, the Commission has set the base cost of gas at zero. Traditionally the base cost of gas had been shown as part of the tariffed rate, along with the margin rate which helped recover costs other than the cost of gas. The remainder of the cost of gas was shown as the PGA rate.

Q. What are the practical effects of setting the base cost of gas to zero?

A. Such a change has no impact on the overall rates customers pay or what their monthly bill will be. The primary effect is that by setting the base cost of gas to zero, the cost of gas will be shown as a separate line item on the customer bill, rather than having the base cost of gas component shown as part of the overall tariff rate, which currently makes it more difficult for customers to understand how the changing cost of gas is reflected on their bills. With the zeroing of the base cost of gas, the monthly PGA rate in the future would incorporate the amounts previously shown as the base cost of gas and the monthly PGA rate.

Q. Has UNS made any recommendations regarding the base cost of gas?

A. Yes. UNS has recommended that the base cost of gas be set at zero.

Q. Do you agree with UNS' proposal regarding the base cost of gas?

A. Yes. Staff agrees with UNS' recommendation to set the base cost of gas at zero. This is consistent with recent Commission Decisions regarding Southwest Gas and Duncan Rural Services and will provide a more clear way of representing the cost of gas on customer bills.

Q. Do you have any further recommendations regarding the proposed change to the base cost of gas?

A. Yes. If the base cost of gas is set at zero and the gas cost is fully reflected in a separate line item, this will represent a change in how rates are represented to customers on their bills. Any such change is likely to result in some amount of customer confusion and misunderstanding. Therefore, I recommend that UNS, as part of implementing any change in how gas costs are shown on customer bills, provide specific customer education materials to explain this change. I further recommend that UNS represent the cost of gas as a specific and separate line item on customers bills, noting in a footnote any temporary PGA surcharge or credit that may be in effect.

Q. Are there any issues related to the mechanics of the PGA mechanism that need to be addressed if the base cost of gas is set at zero?

A. Yes. Zeroing out the base cost of gas will cause the monthly PGA rate component to increase a great deal above its current level, well beyond what a typical application of the PGA bandwith would enable the monthly PGA rate to reflect. To address this sizable shift in the monthly PGA rate and allow the PGA mechanism including the PGA bandwidth to continue functioning on a consistent manner, I recommend that when applying the PGA bandwidth for the first twelve months following the implementation of new rates that UNS compare the new monthly PGA rate to the sum of the base cost of gas and the monthly PGA rate in prior months. This will provide a consistent benchmark for applying the PGA bandwidth while transitioning to a zero base cost of gas.

PURCHASED GAS ADJUSTOR

Q. Please discuss the functioning of the PGA mechanism in recent years.

A. At the time the currently effective PGA mechanism was initially implemented in June 1999, natural gas prices had been relatively low and stable for a number of years. Shortly following implementation, significant changes took place in natural gas markets, leading to higher and more volatile natural gas prices which have made the last five years difficult for regulators, local distribution companies, and consumers of natural gas. Recent years have also provided a stern test of various aspects of the PGA mechanism. Staff believes that in general the PGA mechanism as currently designed and operated has worked well, given the difficult circumstances of recent years. A PGA mechanism by nature determines the manner in which costs are passed through to customers, including such issues as timing and structure of such pass throughs. In a market where the underlying commodity cost has risen from around $2.50 per mmbtu to $6.00 or so in recent years, any PGA mechanism is going to reflect those higher costs, which will be passed through to customers in some fashion, the only variance being the manner in which the rising costs are passed along to customers. No PGA structure can change the underlying fact that natural gas prices and price volatility have increased dramatically in recent years. In general, Staff believes that the current PGA mechanism reasonably balances the interest in shielding customers from price volatility with the competing desire to at least to some extent send a price signal to customers regarding the changing level of the underlying commodity costs. Nonetheless, it is a worthwhile exercise to evaluate the on-going operation of the PGA mechanism and whether adjustments are warranted. UNS has recommended a number of changes to the PGA mechanism, and my testimony below discusses these proposed changes and Staff's recommendations.

Q. How does the PGA bandwidth aspect of the PGA mechanism work?

A. As currently configured, the PGA bandwidth limits the movement of the monthly PGA rate over a 12-month period. The current PGA bandwidth of $0.10 per therm means that each month when a new PGA rate is calculated, the new monthly PGA rate cannot be more than $0.10 per therm different than the monthly PGA rate in any of the previous 12 months.

Q. Please discuss the history of the PGA bandwidth.

A. When the general PGA mechanism framework now in place was implemented in 1999, the PGA bandwidth was set at $0.07 per therm for Arizona natural gas LDCs. Given the predominantly low and stable natural gas prices through the 1990s, it was generally expected that a $0.07 per therm bandwidth would not come into play very often. However, shortly thereafter the price of natural gas rose significantly and became much more volatile, resulting in the PGA bandwidth often limiting the movement of the monthly PGA rate for periods of time. In Decision Number 62994 (November 3, 2000), the

Commission expanded the PGA bandwidth for Arizona LDCs, including Citizens Utilities Arizona Gas Division (UNS' predecessor) to \$0.10 per therm.

Since that Decision the Commission has changed the PGA bandwidth in individual LDC rate cases several times. In Southwest Gas' rate case that concluded in February 2006, the Commission expanded Southwest's PGA bandwidth to \$0.13 per therm. In Duncan Rural Services' rate case that was concluded in March 2006, the Commission expanded Duncan's PGA bandwidth such that the monthly PGA rate can change up to \$0.10 per therm per month, providing the opportunity for the PGA rate to change up to \$1.20 per therm per year. In approving the significant expansion of the PGA bandwidth for Duncan, the Commission cited Duncan's small size and considerable financial constraints.

Q. Has UNS proposed a change to the current PGA bandwidth of \$0.10 per therm?

A. Yes. UNS has proposed that the PGA bandwidth be eliminated or in the alternative be set to \$0.25 per therm for a period of time before being eventually eliminated.

Q. Please discuss UNS' proposal regarding the PGA bandwidth.

A. UNS' proposal to eliminate the PGA bandwidth would have the effect of allowing the monthly PGA rate to fully reflect changes in the 12-month average cost of gas over time. This would reduce the likelihood of UNS carrying a large PGA bank balance for a sustained period of time and would reduce the need for PGA surcharge/credit filings with the Commission. On the other hand, UNS' proposals would potentially expose UNS' customers to very significant movement in the monthly PGA rate within a 12 month or shorter period, without any form of Commission review or approval.

When the PGA bandwidth was initially implemented in 1999, the purpose was to provide a reasonable range for movement of the monthly PGA rate that would capture the changing cost of gas in most instances and also limit the exposure of customers to an automatically changing PGA rate within a one-year period. To some extent even a PGA bandwidth is limited in its protection of customers anyway, as if gas costs reach a high enough level, UNS will simply apply for a temporary PGA surcharge to capture the higher costs that did not fall within the existing bandwidth. In such cases, the nature of the PGA surcharge would be subject to Commission review and approval, providing additional oversight before large gas cost increases are passed along to customers. The previous expansion of the bandwidth from $0.07 to $0.10 per therm was a recognition that additional flexibility in movement of the monthly PGA rate was needed, while still providing some protection for customers.

Q. What is Staff's recommendation for UNS' PGA bandwidth?

A. Staff is cognizant of UNS' desire for greater flexibility in the PGA bandwidth as well as the need for some amount of checks and balances in how gas costs are passed on to customers, particularly in times when gas prices are high and volatile. In recent cases involving Southwest and Duncan, the Commission has shown a willingness to move toward wider bandwidths. Staff believes that some movement to a wider bandwidth is warranted, but that UNS' proposal to eliminate the bandwidth or expand it to $0.25 per therm is moving too far. Staff recommends an expansion of the PGA bandwidth from the current $0.10 per therm to $0.15 per therm. A $0.15 per therm PGA bandwidth provides significant additional room for movement of the monthly PGA rate, while still providing a reasonable limit on the exposure of UNS' customers to an automatic adjustment without Commission review. Staff believes that a $0.15 per therm bandwidth reasonably balances

Company and customer interests. Further, Staff remains open to consideration of further changes to the PGA mechanism in the future, as may be warranted.

Q. Please describe the function of the PGA bank balance thresholds within UNS' PGA mechanism.

A. The PGA bank balance thresholds identify bank balance levels, whether over-collected or under-collected, where UNS is required to take action at the Commission to either address the over or under-collection, or explain why they should not do so at that given point in time. For UNS' PGA mechanism, the bank balance threshold was initially set at $4.45 million (representing the combined thresholds of the then separate Santa Cruz and Northern Arizona divisions). More recently, in Decision Number 68325 (December 9, 2005) the Commission expanded the threshold level for under-collected PGA bank balances to $6,240,000.

Q. Please discuss why the bank balance thresholds were initially created in 1998 and 1999.

A. At the time the thresholds were initially created, they were created to ensure that PGA bank balance levels did not reach very high levels without any action being taken by the utility. In essence they were a trigger to ensure that the utility and the Commission were aware of and would take action as needed to address the balance. At the time, the initial threshold levels were set at points where it was expected that they would only rarely be breeched. This assumption was based upon the history of natural gas prices through the 1990s, when prices were relatively low and stable. Since the initial implementation of these thresholds, the PGA bank balance level has shown much greater volatility than was seen historically, with changes from month to month at times approaching the size of the threshold. The result is that utilities have exceeded the thresholds relatively often in recent years. In light of these circumstances, Staff believes that reconsideration of the PGA bank balance threshold levels is warranted at this time.

Q. How do you believe the threshold on undercollected PGA bank balances should now be approached?

A. In recent years, local distribution companies ("LDCs") that have filed for PGA surcharges have often made such filings before actually reaching the threshold, in anticipation of breeching the threshold in the near future. LDCs have always had the flexibility to file for a PGA surcharge (or credit) at any time as they see fit. With much higher and more volatile natural gas prices in recent years, both the Commission and LDCs are keenly aware of changes in the PGA bank balance and natural gas market conditions. For a larger LDC like UNS, the Company regularly projects a variety of PGA numbers, including bank balances. Staff believes that these circumstances argue for a change in how the threshold on undercollected PGA bank balances is viewed.

A review of the month to month change in the PGA bank balance is also helpful in assessing the amount of change that has taken place in the PGA bank balance in recent years. Appendix B contains a graph of UNS' PGA bank balance since January 2000 and a graph of the raw size of the change in the PGA bank balance each month. Since January 2000, the largest one month change in the PGA bank balance was approximately $12.9 million, from the end of December 2000 to the end of January 2001. The next largest one month change is $7.6 million, with four other months seeing a change greater than $5 million. The second graph shows that one month changes of $5 million or greater appear to be taking place once or twice a year, with accompanying somewhat smaller changes. A review of the cumulative change over a seasonal timeframe shows a number of occasions where swings in the PGA bank balance are $10 million or more. Given this history of large PGA bank balance swings, retention of the current, relatively small threshold levels indicates the Commission is likely to continue to see filings from UNS to address PGA bank balance levels on a regular basis.

Given these circumstances, Staff believes that for UNS the Commission should consider eliminating the bank balance threshold in relation to under-collected PGA bank balances. Given high and volatile natural gas prices that appear likely to continue in the near term future, both the Commission and UNS carefully monitor the functioning of UNS' PGA, including the changing size of the PGA bank balance. Further, UNS and other LDCs have shown a strong interest in addressing undercollected PGA bank balances on a timely basis, so it is unlikely that UNS' undercollected PGA bank balance would grow to very large proportions without action by the Company. Elimination of the threshold on undercollections would, in essence, provide the utility with the discretion to apply for a PGA surcharge when it believes such an action is warranted, while also providing the flexibility for UNS to avoid such an action if the Company believes changing market conditions do not require such a filing. Staff believes that elimination of the threshold on undercollected PGA bank balances would result in a more smooth operation of the PGA, given the relatively common sizable monthly movements of the PGA bank balance, that at times exceed the size of the threshold itself. Staff therefore recommends elimination of the currently effective threshold on undercollected PGA bank balances.

Q. How does Staff believe that the threshold on overcollected PGA bank balances should be treated?

A. While Staff believes that much of the previous discussion of the threshold on undercollected PGA bank balances also applies to overcollections, there is an additional public interest aspect to avoiding the growth of an overcollected PGA bank balance to exorbitant levels. On the other hand, provision for UNS to carry an overcollection of some size can help provide a cushion to customers when natural gas market prices rise significantly, as has happened a number of times in recent years. Under the current threshold level, any sizable increase in natural gas market prices will likely result in UNS swinging to a sizable undercollected PGA bank balance, even if they had a bank balance close to the current threshold requiring UNS to take action. The current threshold level for overcollections of $4.45 million is sufficiently small that UNS could conceivably exceed the threshold, appear before the Commission to implement a credit, and see their balance swing to a sizable undercollection in a short period of time, with UNS still paying out the credit. Additionally, given volatile market conditions and the size of changes UNS customers have seen over the past years, a refund of $4.45 million over UNS' customer base is a relatively small amount per therm, approximately $0.04 per therm, given recent sales levels.

Staff believes that the cushioning benefit of having a higher threshold level on overcollections, in addition to the administrative efficiency of not having a threshold level that can be easily exceeded in a month, argues for increasing the threshold level on overcollections substantially. The size that such an increase should be is not entirely clear. Staff believes that a reasonable level given UNS' size and on-going market conditions would be $10 million. At such a level UNS could have a sizable cushion for customers against a run up in market prices, while still providing substantial relief to customers when the higher threshold level is breeched. Staff believes that such a higher threshold is both administratively more efficient given significant market volatility, and provides the possibility of a substantive cushion for movement in the PGA bank balance toward an undercollection before customers would be likely to face a PGA surcharge.

Therefore, Staff recommends that the PGA bank balance threshold for overcollections for UNS be set at $10 million dollars.

Q. UNS makes a general proposal on page 15 of Mr. Hutchins' direct testimony that when approving a surcharge, the Commission should approve a surcharge which will eliminate the PGA bank balance in a reasonable time. Please comment.

A. As a general principal, Staff agrees with UNS' sentiment as expressed by Mr. Hutchins on page 15 of his direct testimony, subject to recognition that each time the Commission addresses a PGA surcharge (or PGA credit) there are unique circumstances and changing natural gas market conditions which should be considered. Additionally, it should be noted that the PGA bank balance changes from month to month, often in unexpected directions over time, as weather and other factors impact natural gas market conditions during the period when a PGA surcharge (or credit) may be in effect. So absent a provision that a PGA surcharge (or credit) be in place until the PGA bank balance reaches zero, it will always be uncertain whether a given PGA surcharge (or credit) will eliminate the PGA bank balance that existed at the time such a surcharge (or credit) was implemented.

Q. UNS has proposed changes to the interest rate to be applied to the PGA bank balance. Please describe UNS' proposed changes.

A. UNS is proposing to increase the interest rate applied to the PGA bank balance. It appears UNS is proposing to apply one interest rate, the London Interbank Offered Rate ("LIBOR") plus 1.5 percent, to the portion of the PGA bank balance that is below twice the current PGA bank balance threshold. For the portion of the PGA bank balance above twice the current PGA bank balance threshold, UNS proposed to apply its authorized weighted average cost of capital as determined in this proceeding. It appears that UNS is of the PGA bank balance adds administrative complexity to the PGA mechanism and absent a compelling need to make multiple interest calculations each month, Staff prefers to apply a single interest rate to the PGA bank balance. Further, Staff is not convinced that a separate interest rate is necessary for the portion of the PGA bank balance above $12.48 million. While UNS has had a PGA bank balance above $12.48 million at times in the past, it is important to note that in recent years natural gas prices have been on a general upward trend, so by nature the PGA bank balance will tend toward an undercollection. However, natural gas prices do not always trend upward and the recent trend's impact on UNS' PGA bank balance on recent years should not be assumed to continue into the future. For example, in 2006, natural gas prices generally trended downward, and UNS has now had an overcollected PGA bank balance since the end of June 2006. Further, the Commission could grant a very large PGA surcharge to address a certain size PGA bank balance, but given the vagaries of the natural gas market, the PGA bank balance could still remain undercollected for many months if natural gas prices moved upward during that time. Indeed, in recent PGA surcharge applications, the Commission has considered in its deliberations, information that UNS and other LDCs have provided about their projections of future PGA bank balance levels in an effort to, among other things, avoid large PGA bank balances for long periods of time.

Q. Please discuss the LIBOR rate UNS is proposing to use for the interest rate.

A. It is not entirely clear what specific LIBOR rate UNS is proposing to use or where this rate would be found if the Commission were to adopt it. A review of end of May 2006 LIBOR rates on the British Bankers Association (which publishes the LIBOR) website shows rates ranging from approximately 5.07 percent for the one week rate to 5.42 percent for the one year rate. However, if the rate used in Mr. Hutchins' example on page 13 of his testimony is correct, that the LIBOR rate is relatively similar to the existing interest rate being applied to the PGA bank balance (4.53 percent vs. 4.43 percent), so in that case it would appear that the more significant change is the additional 1.5 percent of interest UNS wishes to collect in addition to the LIBOR.

Q. Has the Commission to date indicated that it wishes to grant interest on the PGA bank balance to an LDC that would exactly match the utility's cost of borrowing to carry any PGA bank balance?

A. No. When the Commission first granted interest on the PGA bank balance in 1999, it was clear that the interest rate being adopted at that time was not equal to any LDC's expected costs of borrowing. Additionally, in rate cases since that time, the Commission has not adopted an interest rate that was considered to be equivalent to the LDC's cost of borrowing. In the recent Southwest Gas rate case (Decision Number 68487, dated February 23, 2006), the Commission adopted an interest rate for Southwest Gas, the one-year nominal Treasury constant maturities rate, that is similar to the current interest rate for UNS. Additionally, the Commission adopted the same interest rate for Southwest Gas as for Arizona Public Service. UNS has not demonstrated that it is somehow so different from other Arizona utilities that it somehow warrants a higher or two-tier interest component.

An additional aspect of this discussion is that the Company's cost of borrowing is likely to change over time, so it is unlikely that there is any simple method of setting an interest rate to specifically track UNS' exact cost of borrowing, even if the Commission wished to do so.

Also, as a general principle, to the extent an LDC receives an interest rate on the PGA balance that might be expected to fully compensate it for the costs of borrowing (or even possibly overcompensate), there could be a concern that the LDC would become less concerned with reducing the PGA bank balance and could become less focused on taking all steps necessary to reduce the cost of natural gas for its consumers.

Further, as was noted in 1999 when the Commission began allowing interest to be collected on PGA bank balances, the higher the interest rate the Commission grants for PGA bank balances, the more the resulting interest will make the PGA bank balance more volatile. The level of such additional volatility is not enormous, but the cumulative effect can be noticeable over time.

Q. Do the other changes Staff is proposing for the PGA mechanism relate to this discussion of the interest rate on the PGA bank balance?

A. Yes. Staff believes that its proposal to substantially expand the band on the monthly PGA rate, in addition to expanding and eliminating the thresholds on the PGA bank balance, will reduce the likelihood of UNS incurring substantial PGA bank balances for long periods of time and provide UNS with additional flexibility in how they respond to on-going changes to the PGA bank balance.

Q. What is your recommendation in regard to the interest rate on UNS' PGA bank balance?

A. Given the circumstances discussed above, Staff believes that the existing interest rate that is applied to UNS' PGA bank balance, the monthly three month commercial financial paper rate, should be retained and is a reasonable balance of UNS' and ratepayer interests. As an alternative, Staff would not oppose moving UNS to the one-year nominal Treasury constant maturities rate.

Q. Do you have any further recommendations regarding the interest rate to be applied to the PGA bank balance?

A. Yes. I recommend that if for some reason in the future the then applicable interest rate becomes unavailable for one or more months, the previous month's interest rate would apply to the month(s) where no interest rate is available. Further, I recommend that if the then applicable interest rate becomes unavailable on a recurrent basis, UNS may file with the Commission to replace the interest rate with another interest rate, with the underlying presumption being that any replacement interest rate would be similar in nature to the then applicable rate.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. My testimony includes the following recommendations:

1. The base cost of gas should be set at zero.
2. UNS, as part of implementing any change in how gas costs are shown on customer bills, should provide specific customer education materials to explain this change. I further recommend that UNS represent the cost of gas as a specific and separate line item on customers bills, noting in a footnote any temporary PGA surcharge or credit that may be in effect.
3. During application of the PGA bandwidth for the first 12 months following the implementation of new rates UNS should compare the new monthly PGA rate to the sum of the base cost of gas and the monthly PGA rate in prior months.
4. The bandwidth on the monthly PGA rate should be expanded to $.015 per therm.
5. The threshold on the PGA bank balance for undercollected balances should be eliminated.

6. The threshold on the PGA bank balance for overcollected balances should be set at $10 million.

7. The currently applicable interest rate for the PGA bank balance should be retained.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME

ROBERT G. GRAY

Education

B.A. Geography, University of Minnesota-Duluth (1988)
M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Senior Economist (August 1997 - present), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses on a variety of natural gas issues in Arizona, including gas procurement, rate design, interstate pipeline issues, revenue decoupling, energy conservation, low income issues, natural gas research and development funding, customer services issues, special contracts, various tariff matters, and other natural gas issues. Prepare recommendations and present written and oral testimony before the Commission on various utility industry issues. Represent the ACC in natural gas proceedings at the Federal Energy Regulatory Commission and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas, including serving in my current position as Chair of the NARUC Staff Subcommittee on Gas.

Testimony

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Southern California Edison Devers – Palo Verde 2 Transmission Line Application before the Arizona Power Plant and Line Siting Committee , (L-00000A-06-0295-00130), 2006.

Semstream Arizona Propane Acquisition of Energy West (Docket G-02696A-06-0515), Arizona Corporation Commission, 2006.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A., Vol. 27A, 1993, pp. 1-12.

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Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

Staff Report on Purchased Gas Adjustor Mechanisms, (Docket No. G-00000C-98-0568) Arizona Corporation Commission, October 19, 1998.

Staff Report on the Rolling Average PGA Mechanism, (Docket No. G-00000C-98-0568),Arizona Corporation Commission, September 6, 2000.

Staff Report on the Use of a Circuit-Breaker in Adjustor Mechanisms, Arizona Corporation Commission, September 3, 2003.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. G-01551A-04-0192), Arizona Corporation Commission, June 2, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. E-01345A-04-0273), Arizona Corporation Commission, August 16, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project , (Docket No. E-01345A-05-0895), Arizona Corporation Commission, March 2, 2006.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-01551A-060107), Arizona Corporation Commission, May 16, 2006.

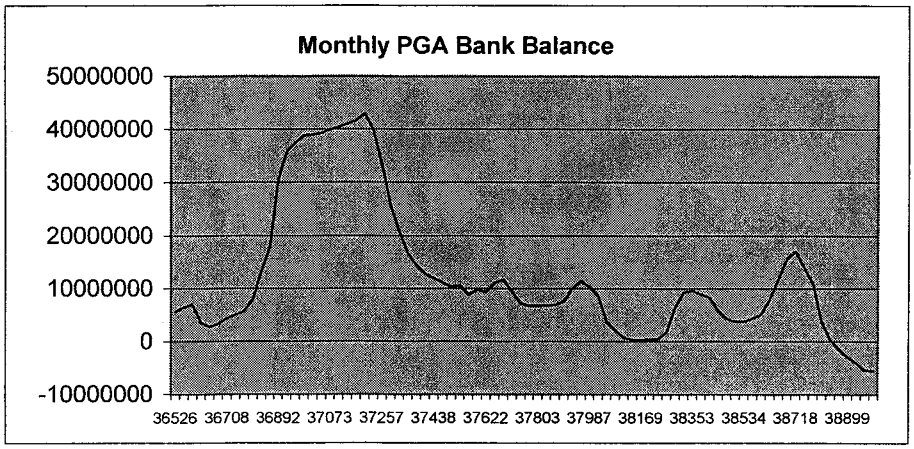
Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition
1997	NARUC 6th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7th Annual Natural Gas Conference
1999 – 2006	NARUC Summer Committee Meetings
2001	Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2006	NARUC Winter Committee Meetings
2004-2006	NARUC Annual Convention

Memberships

NARUC - Staff Subcommittee on Gas – Vice-Chair (2002 - 2004)
NARUC - Staff Subcommittee on Gas – Chair (2005 -)
Michigan State Institute for Public Utilities – NARUC Advisory Committee
North American Energy Standards Board Advisory Council

Schedule RGG-2, PGA Bank Balance Information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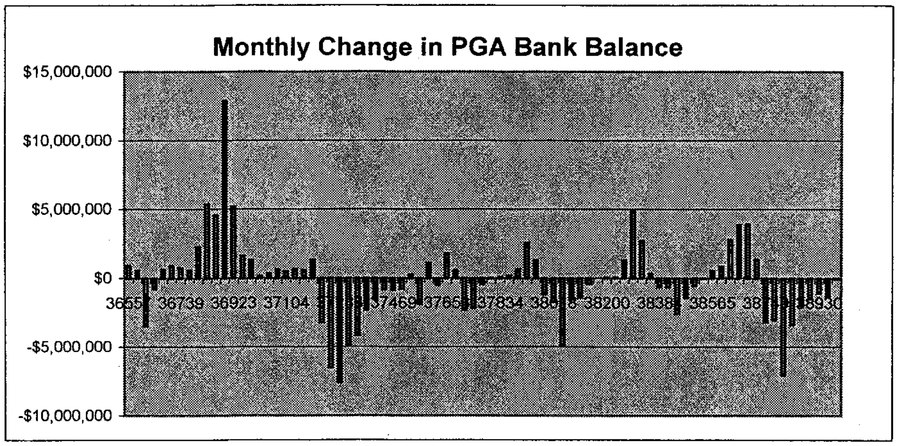
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-$5,000,000
-$10,000,000
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BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	)	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	)	DOCKET NO. G-04204A-05-0831

DIRECT

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST II

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 9, 2007

TABLE OF CONTENTS

ATTACHMENT

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NOS. G-04204A-06-0463, G-04204A-06-0013
AND G-04204A-05-0831

On July 13, 2006, UNS Gas, Inc. ("UNS") filed an application with the Arizona Corporation Commission ("Commission") for an increase in its rates throughout the State of Arizona. Included in this application is a request for approval of UNS' proposed Demand-side Management ("DSM") programs, including movement of its existing Low-Income Weatherization ("LIW") program into the new DSM portfolio. Funding is to be increased for the LIW program and UNS proposes that an emergency bill payment component be added. In addition, UNS proposes to change the existing Customer Assistance Residential Energy Support ("CARES") program from a six-month per therm discount on the first 100 therms to a year-round discount on the monthly customer charge.

On September 8, 2006, the Commission granted the Motion to Consolidate the Rate Case (Docket No. G-04204A-06-0463) with the PGA Case (Docket No. G-04204A-06-0013) and the Prudence Case (G-04204A-05-0831). Having read UNS' Direct Testimony, Staff recommends the following:

1. UNS should continue to work toward expanding participation in the CARES program to additional eligible households.

2. The CARES program monthly customer charge should remain at its current level, and the current per therm discount should be retained.

3. The deferred account for the CARES program should be discontinued.

4. UNS should submit detailed DSM program proposals to the Commission as soon as possible, rather than waiting for the conclusion of the UNS Electric rate case.

5. Emergency bill assistance should not be included in the DSM portfolio. Emergency bill assistance, in the amount of $21,600, should be funded from base rates and combined, as an additional funding source, with the existing Warm Spirit emergency bill assistance program.

6. UNS should file a comprehensive DSM portfolio plan for Commission approval, along with detailed program proposals for each of the new DSM programs it wishes to pursue.

7. When filing its detailed DSM program proposals, UNS should include the data required to calculate the cost-effectiveness of each program on a Societal Test basis.

8. As part of its DSM portfolio filing, UNS should provide information for the LIW program, including marketing, verification and inspection, and cost-effectiveness.

9. UNS should create a monitoring plan for each DSM program and describe these plans in each program proposal.

10. UNS should submit semi-annual DSM reports.

11. UNS should recover its costs for all of its DSM programs through a separate DSM adjustment mechanism. The initial DSM charge, to fund the ongoing LIW program, should be set at $0.00082 per therm.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Julie McNeely-Kirwan. I am a Public Utilities Analyst II employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst II.

A. In my capacity as a Public Utilities Analyst II, I review monthly filings of purchased gas adjustors. My duties include reviewing annual utility affiliated interest reports for compliance and evaluating demand-side management programs submitted for approval to the Commission.

Q. Please describe your educational background and professional experience.

A. In 1979, I graduated magna cum laude from Arizona State University, receiving a Bachelor of Arts degree in History. In 1987, I received a Master's Degree in Political Science from the University of Wisconsin, Madison. I have been employed by the Commission since September of 2006.

Q. What is the subject matter of this testimony?

A. This testimony will present Staff's analysis and evaluation of UNS Gas, Inc.'s ("UNS") low-income assistance programs and proposed demand-side management ("DSM") programs, including movement of its Low-Income Weatherization ("LIW") program from the Low-Income Assistance programs into the DSM portfolio.

LOW-INCOME ASSISTANCE PROGRAMS

Q. What low-income assistance programs does UNS provide for its customers?

A. UNS provides its Customer Assistance Residential Energy Support ("CARES") discount program, the Warm Spirit emergency bill assistance program and the Low-Income Weatherization program, which helps low-income customers to improve the energy efficiency of their homes. UNS has proposed moving the LIW program into its DSM portfolio, so the LIW program will be discussed later in this testimony, in the section on demand-side management.

Q. Please describe the current CARES program.

A. Households with income equal to 150% percent, or less, of the Federal Poverty Guidelines can receive a $0.15 per therm discount from November through April. This per therm discount only applies to the first 100 therms used. Due to changes made to certification procedures in 2004, participants can enroll in less than 20 days; the requirements for yearly recertification were also eased. (Tobin L. Voge, p. 10; Gary A. Smith testimony, pp. 9-10; Decision No. 67434, December 3, 2004)

Q. How many UNS customers participate in the CARES program, and how has participation changed over time?

A. In January 2004, CARES participation was at 2,251, or 1.9% of residential customers. Two years later, as of January 2006, CARES-enrolled households numbered 5,670, or 4.4% of residential customers; by June 2006, participation was 5,989, or 4.6% of residential customers. Staff recognizes the improvement and recommends that UNS continue to work toward expanding participation in the CARES program to additional eligible households. (Semi-Annual Reports, UNS Gas, Inc.'s and UNS Electric, Inc.'s CARES Discount Programs, August 6, 2004, January 30, 2006 and July 27, 2006)

Q. Does UNS propose to change the CARES program?

A. Yes. UNS proposes to discount the monthly residential customer charge by $6.50 on a year-round basis and to eliminate the $0.15 per therm discount. (Tobin L. Voge, p. 10; Gary A. Smith testimony, p. 10)

Q. Has UNS proposed other changes that would affect the monthly customer charge paid by CARES customers?

A. Yes. In addition to the $6.50 year-round discount, UNS has requested increases in the monthly residential customer charge for all customers, from $7 year-round to $20, April through November, and $11, December through March. (UNS Gas, Inc. PPS-1 Pricing Plan Summary; Testimony of Tobin L. Voge, p. 9-10).

If the proposed discount and monthly charges were both approved, they would:

(i) increase the monthly customer charge from $7 to $13.50 for eight months of the year;

(ii) decrease the monthly customer charge from $7 to $4.50 for four winter months; and

(iii) increase the annual amount paid in monthly residential customer charges from $84 to $126.

Please see, also, testimony of Staff Witness Steve Ruback regarding Staff recommendations concerning changes to the monthly service charge.

Q. Has UNS proposed other changes that would affect the per therm charge paid by CARES customers?

A. Yes. In addition to proposing elimination of the CARES per therm discount, UNS proposes to decrease the year-round margin, for all customers, from $0.3004 to $0.1862. (UNS Gas, Inc. PPS-1, effective December 3, 2004; Schedule H-3) For CARES customers this would mean an increase of $0.0358 per therm, from November through April, for the first 100 therms used; for usage over 100 therms, it would mean a decrease of $0.1142 per therm.

Q. How many therms does the average CARES customer use?

A. The average CARES customer used 64 therms per month during winter of the test year. (Tobin L. Voge testimony, p 10)

Q. Do the proposed changes benefit UNS CARES program participants?

A. The proposed changes do not benefit most CARES customers. The change in discount is projected to increase savings for the average CARES participant by 34%. (Tobin L. Voge testimony, p. 10) However, these savings are based on discounting increased monthly fees; on an annual basis, CARES customers would be paying more in monthly customer charges, even with the year-round $6.50 discount. Also, the average CARES customer would be paying more, per therm, during the November through April period, experiencing a decreased per therm rate only on usage over 100 therms. In general, higher-usage customers would benefit, while lower-usage customers would see increases.

Q. What would be the impact of the changes on average monthly bills for CARES customers?

A. From April through November, with the higher monthly charge, CARES customers using the fewest therms (5-50 therms) would experience increases ranging from $0.79 (3.60%) to $5.93 (69.74%). Higher-usage customers (75-500 therms) would experience decreases ranging from $2.06 (6.98%) to $50.58 (32.17%).

During the December through March period, with the lower monthly charge, both lower-usage (5-50 therms) and higher-usage (250-500 therms) customers would experience decreases -- $0.69 (4.74%) to $2.32 (29.92%) for lower-usage customers, and $1.12 (5.11%) to $44.54 (31.33%) for higher-usage customers. Customers in the middle range, 75-100 therms, would experience increases of $0.22 (1.20%) to $1.12 (5.11%). (UNS, Schedule H-4, Typical Bill Comparison, Present and Proposed Rates.)

Q. Does UNS anticipate any impact on customer gas usage from the proposed change to the CARES program?

A. UNS has not done the price elasticity study that would be required to quantify the impact of the proposed change on gas usage. (UNS' response to Staff's data request STF 12.2)

Q. What other benefits are there to participating in the CARES program?

A. CARES participants are exempt from paying the current Purchased Gas Adjustor ("PGA") surcharge. It should be noted that the PGA surcharge will end after April 2007 (Decision No. 69169).

Q. Does Staff recommend that the changes be made to the CARES program as proposed by UNS?

A. No. The changes proposed by UNS would have a disproportionate impact on low-usage CARES customers and eliminate the incentive to conserve provided by the current per therm discount. The typical bill comparison shows that customers using the fewest therms would experience the largest percentage increases in their monthly bills, particularly during the eight months of higher monthly customer charges. (Schedule H-4, p. 2; Schedule H-5, p. 2)

Another potential negative impact could occur in November and April, when some UNS-served areas are still experiencing cold weather; during these months, CARES customers would be paying both the higher monthly charge and the increased margin rate for less than 100 therms. The UNS response to STF 15.5 includes a table showing proposed increases ranging from 46% to 86.19% for CARES customers using 100 therms or less during November and April. This would both impact low-usage customers and run counter to the practice of targeting CARES relief for colder months, in order to meet home heating needs.

Staff recommends that the CARES program monthly customer charge remain at its current level, as an added benefit to CARES customers, and that the current per therm discount be retained.

Q. Would an adjustment to test year data be required with respect to Staff's recommendations on CARES discounts?

A. Staff's proposal will probably result in an adjustment to test year data, depending on the level of monthly customer charge(s). The level of adjustment will be discussed in Staff's surrebuttal testimony.

Q. What impact has the CARES program surcharge exemption had on the PGA bank balance?

A. From November 2005 through March 2006 the reduced PGA bank balance collection was $308,731, while the currently projected reduction for all of 2006 is nearly $568,000. (UNS' responses to Staff's data request STF. 12.1; James Pignatelli testimony, p. 19) As of November 2006, UNS reported an over-collected bank balance of $4,727,307.36. (November 2006 UNS Monthly Purchased Gas Adjustor Report).

Q. How did UNS treat CARES discounts and program expenses in its application?

A. On October 29, 1999, Decision No. 59875 ordered that Citizens record income and expenses for its Low-Income Residential Assistance Programs in a deferred account and compare the total to the revenues collected. The UNS CARES deferred account functions as a tracking account, resulting in a balance between amounts spent and amounts accrued. In the current rate case, UNS is seeking to recover a balance of $107,477 on an amortized basis over three years. (Karen Kissinger testimony, p.15; UNS response to RUCO's data request 1.10, UNS Gas CARES Deferral Calculation Adjusted Schedule, December 31, 2005; also Change to Residential Customer by Rate – All Regions)

It appears that the deferred account was originally ordered to ensure that monies collected for low-income residential assistance programs were actually spent on those programs.

However, in 2005, UNS spent $175,562 more on the CARES program than it collected. Given the increased CARES enrollment levels and the attendant increases in discounts and program expenditures, Staff recommends that UNS discontinue the deferred account.

Q. Please describe the Warm Spirit program.

A. The UNS Warm Spirit program provides emergency bill assistance to low-income customers, using shareholder funds to match customer donations. UNS also provided a one-time donation of $50,000 in 2004. Matching fund donations range between $20,000 and $25,000 yearly, with the funds distributed by local social service agencies. UNS does not propose any changes to the Warm Spirit program. (Gary A. Smith testimony, pp. 10-11; James S. Pignatelli testimony, pp. 18-19) However, Staff proposes that the $21,600 in emergency bill assistance proposed by UNS as a part of the LIW program be moved, instead, into the Warm Spirit program as an additional source of funding.

DEMAND-SIDE MANAGEMENT ("DSM")

Benefits and Costs of DSM

Q. What is DSM?

A. DSM is planning, implementation and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand and/or to reduce energy consumption in a cost-effective manner. DSM may include the following: (1) energy efficiency, meaning products, services or practices that provide equal or superior service while consuming less energy; (2) load management, meaning actions by a utility to reduce peak demands or improve system operating efficiency; and (3) demand response, meaning intentional modification of customer energy consumption patterns, including the timing or quantity of demand.

Q. Do any of the DSM programs proposed by UNS Gas shift peak load or reduce peak demand?

A. The main purpose of the proposed UNS DSM programs is to cut down on the number of therms consumed; however, UNS states that, although no demand analysis has been prepared to measure the effects, a gas peak reduction would also result. (UNS' response to Staff's data request, STF 12.3)

Q. Do DSM programs benefit both UNS and the rest of society?

A. Yes. Benefits to both UNS and society include meeting the demand for natural gas less expensively than through purchasing additional supplies of natural gas and delaying the need for construction of new infrastructure, including plants, storage facilities and pipelines. Societal benefits also include decreased pollution and emissions of carbon dioxide and methane, both greenhouse gases (see www.naturalgas.org). In addition, DSM programs can assist in conserving a finite natural resource.

Q. Why should UNS and Staff consider the benefits and costs of DSM to society as well as to UNS?

A. Since the benefits and costs of a DSM program for society may be different from those for a utility, the benefits and costs for both should be considered. In its 1991 resource planning decision, the Commission adopted the use of the Total Societal Test. (Decision No. 57589, dated October 29, 1991)

Q. Are avoided environmental impacts included in evaluating the cost-effectiveness of a DSM program?

A. Yes, as part of the societal benefits. The Commission directed that environmental concerns be considered in resource planning (Decision No. 57589, dated 10/29/91), and DSM is a part of resource planning.

Q. What are the societal costs of a DSM program?

A. The societal costs of a DSM program consist of the incremental costs of the DSM program (including incremental utility costs and incremental customer/vendor costs). Such costs may include the cost of equipment, the cost of installation, training costs for workers who install or repair energy-efficient equipment and administrative costs. Incentives to customers to participate in a DSM program are transfer payments, not societal costs. Transfer payments are transfers of income from one person or organization to another, without goods or services being supplied in exchange for these transfers.

UNS' Current DSM Program

Q. What has UNS proposed regarding DSM?

A. UNS has proposed a preliminary portfolio plan for four new DSM programs, a DSM cost recovery mechanism, and movement of its enhanced and modified LIW program into the DSM portfolio. UNS proposes to file the four new DSM program proposals with the Commission 120 days after resolution of the UNS Electric rate case, Docket No. E-04204A-06-0783. (UNS' response to Staff's data request JM 8.12).

Q. Does Staff agree with UNS waiting until conclusion of the UNS Electric rate case?

A. No. Staff recommends that UNS submit detailed program proposals to the Commission as soon as possible, rather than waiting for the conclusion of the UNS Electric rate case, in which a decision is not expected until 2008.

Q. Please provide background on UNS' current DSM program.

A. The only DSM-type program currently provided by UNS is its Low-Income Weatherization ("LIW") program, currently part of UNS' customer assistance programs. This program was in place when UniSource Energy Corporation purchased Citizen's Communications Company in 2003. (UNS' response to Staff's data request JM 8.5).

Q. What is the current level of funding for LIW, and how is it funded?

A. The annual budget is $75,000 and is funded through operating expenses, in base rates. (Gary A. Smith testimony, p. 11; UNS' response to Staff's data request JM 8.6.) Although not currently an approved DSM program, UNS has now asked for Commission approval of LIW as a DSM program, also proposing a $60,000 increase in budget and transfer into the proposed DSM portfolio. (Gary A. Smith testimony, pp. 11-13.)

Q. Please describe the current LIW program.

A. In its current form, the LIW program provides energy efficiency improvements to homes occupied by UNS customers with household incomes at or below 150% of the Federal Poverty Guidelines (FPG). As an example, 150% of the FPG for a family of four would be $30,000. (http://liheap.ncat.org/profiles/povertytables/FY2007/pop130.htm) UNS provides up to $2,000 for weatherization of each household, installing measures that include improved insulation, weather stripping and furnace replacement. (Gary A. Smith Testimony, p. 12.)

Q. Please describe the nature of the enhancement proposed by UNS.

A. UNS proposes to increase funding for LIW by $60,000, from $75,000 to $135,000, and to allocate $21,600 of this amount to a new emergency bill assistance component. (Gary A. Smith Testimony, p. 11)

<u>**UNS' Emergency Bill Assistance**</u>

Q. Please describe the emergency bill assistance component of the proposed, enhanced, Low-Income Weatherization program.

A. UNS has proposed allocating $21,600 of the LIW budget to a new emergency bill assistance program for utility customers with household incomes at or below 150% of the FPG. Customers must present a delinquent or unpaid bill and may receive no more than $400 in assistance during any 12-month period. Administration is to be done by community action agencies under contract to UNS. (Gary A. Smith testimony, p. 12.)

Q. Would the LIW emergency bill assistance program be in addition to the emergency bill assistance program already in place as part of the Warm Spirit program?

A. Yes. (Gary A. Smith testimony, pp. 10-11)

Q. How do the existing (Warm Spirit) and proposed (LIW) emergency bill assistance programs differ?

A. The existing Warm Spirit program is funded, as stated above, by customer and shareholder donations, and the funds are provided to community action agencies. The Low-Income Weatherization program, if approved as a DSM program, would be funded through the proposed DSM adjustor, and the funds would be distributed through UNS' Weatherization

Program partners, also community action agencies. Income requirements (150% of FPG) for the two emergency bill assistance programs would be the same. (UNS' response to Staff's data request JM 8.2)

Q. Is emergency bill assistance a Demand-side Management ("DSM") program?

A. No. Emergency bill assistance, although a benefit for customers in crisis situations, is a low-income assistance program and should not be included in the DSM portfolio. There are several negative consequences to including emergency bill assistance within a DSM program:

(i) UNS has proposed a separate DSM per therm charge, and Staff supports this proposal as the preferable method for funding DSM (as discussed later in this testimony). If emergency bill assistance is funded through a separate DSM adjustor it may not be clear to ratepayers that they are also paying for a non-DSM program through the DSM charge;

(ii) funding a non-DSM program through a DSM adjustor reduces clarity regarding the total funding level for actual DSM programs; and

(iii) inclusion of non-DSM components within the DSM program could reduce clarity regarding the objectives of the DSM program.

Staff recommends that the UNS proposal for total DSM spending be reduced by $21,600 and that this amount be funded from base rates and combined, as an additional funding source, with the existing Warm Spirit emergency bill assistance program. Therefore, test year expenses should be increased by $21,600, as discussed in the testimony of Staff witness Ralph Smith.

Q. Did UNS calculate cost-effectiveness or therm savings for the Low-Income Weatherization program?

A. No. The therm savings and cost-effectiveness ratios for the LIW program were requested in Staff's data requests JM 8.7 and JM 8.8. UNS stated that it "did not project cost-effectiveness for the Low-Income Weatherization program" because the program was ordered by Decision No. 59875. Staff's review of Decision No. 59875 shows that the Decision authorized an annual allowance for low-income residential assistance programs, but does not specifically address a weatherization program.

Q. Should the therm savings and cost-effectiveness of the LIW program be determined?

A. Yes. Even though a low-income weatherization program may not be as cost-effective as other DSM programs, it should be as cost-effective as is reasonably possible. Measures included in low-income programs should be generally cost-effective.

UNS' Proposed New DSM Programs

Q. What new DSM programs has UNS proposed?

A. UNS has proposed four new DSM programs, two for Residential customers and two for Commercial customers. The Residential programs consist of (1) Residential Furnace Retrofit; and (2) Residential New Construction. The Commercial programs consist of (1) Commercial HVAC (Heating, Ventilation and Air Conditioning) Retrofit and (2) Commercial Gas Cooking Efficiency. (Exhibit GAS-1; Gary A. Smith testimony, pp. 13-15)

Q. Please describe the selection process and criteria for the proposed UNS DSM programs.

A. UNS reviewed 32 ongoing or proposed programs from Tucson Electric Power, APS, Southwest Gas and the Public Service Company of New Mexico. These programs were ranked according to the following seven criteria:

(i) Applicability to existing customer base;
(ii) Consistency with area demographic and growth trends;
(iii) Potential cost effectiveness;
(iv) High incentive value;
(v) Consistency with societal goals;
(vi) Existing delivery infrastructure; and
(vii) Whether a program complements existing programs.

(Gary A. Smith testimony, pp. 16-17)

Q. How did UNS assess the cost-effectiveness of its proposed DSM programs?

A. UNS used both the Total Resource Cost Test ("TRC") and the Participant Test ("PT") to evaluate the cost-effectiveness of its DSM programs, with the exception of the Low-Income Weatherization program. (Gary A. Smith testimony, p. 17; Exhibit GAS-1) The TRC test compares avoided utility costs against incremental utility and participant costs (excluding incentives paid). The Participant Test compares incentives received and bill reductions against bill increases and incremental participant costs. The Societal Test starts with the Total Resource Cost Test, but includes non-market benefits to society due to DSM, such as reduced environmental effects of energy production and delivery.

Staff recommends that, when filing its detailed program proposals, UNS include the data required to calculate the cost-effectiveness of each program on a Societal Test basis.

Q. Please describe the proposed Residential Furnace Retrofit program.

A. The Residential Furnace Retrofit program is designed to provide residential customers, including multi-family homeowners, with incentives to purchase gas furnaces with an Annual Fuel Utilization Efficiency ("AFUE") of at least 90%. The program would also provide training for contractors to install and operate residential high-efficiency gas furnaces. (Gary A. Smith testimony, p. 13)

Q. What would be the incentive provided under this program, and what is the incremental cost of a high-efficiency gas furnace?

A. The cash incentive for high-efficiency gas furnaces would be $150. (UNS' response to Staff's data request STF 12.7) The total incremental cost of a high efficiency gas furnace, for a furnace at 90-92% AFUE, is $710. (UNS' response to Staff's data request STF 12.7).

Q. Is the Residential Furnace Retrofit program intended to encourage the replacement of functioning standard furnaces with high-efficiency gas furnaces, or is it only intended to replace standard furnaces that are no longer functioning?

A. The incremental cost assumes replacement at the end of a furnace's functional life and does not, for this reason, include labor costs. (UNS' responses to Staff's data request STF 12.2)

Q. What portion of the budget would go to training contractors for the Residential Furnace Retrofit Program?

A. Training is estimated at $5,000 per year. (UNS' response to Staff's data request STF 12.11)

Q. Please describe the proposed Residential New Construction Program.

A. The Residential New Construction Program would provide builders of residential construction projects with incentives to install energy efficiency measures, including improvements to the building envelope and windows; improvements to heating, cooling and water-heating systems; and other measures such as controlled air filtration and tightened air duct systems. (Gary A. Smith testimony, p. 14)

Q. What would be the incentive offered to builders under this program, and what would be the total incremental cost?

A. The UNS Residential New Construction Program would offer an incentive of $400 per house. The estimated incremental cost, per home, is $1,360. This incremental cost covers upgrades to the shell and HVAC equipment. (UNS' response to Staff's data request STF 12.15)

Q. Are any other incentives available to contractors participating in the UNS Residential New Construction program?

A. If builders or contractors construct homes heated or cooled with 50% more energy efficiency than the baseline established in the International Energy Conservation Code, a $2,000 federal tax credit may be available to them under the U.S. Energy Policy Act of 2005 (EPAct 2005). (UNS' response to Staff's data request JM 8.12. (See UNSG0463/04922))

Q. Please describe the proposed Commercial HVAC Retrofit Program.

A. The Commercial HVAC Retrofit Program would provide incentives to business owners to improve the energy efficiency of their gas-fueled space and water heating systems. In addition, training would be provided to contractors, who would also be permitted to take part in a referral program. (Gary A. Smith testimony, p. 15)

Q. Please describe the qualified contractor's referral program.

A. UNS Gas intends to set minimum standards that must be met for a contractor to appear on the referral list, such as licensing, bonding, certifications and records with the Registrar of Contractors and the Better Business Bureau. UNS Gas would publish the referral list on its website and in brochures; a contractor on the referral list would have to resolve UNS customer complaints or be removed from the list. (UNS' response to Staff's data request STF 12.13)

Q. What would be the incentives offered by the Commercial HVAC Retrofit program, and what would be the total incremental costs?

A. The Commercial HVAC Retrofit program would offer a $150 incentive for a small boiler with 84.5% or better efficiency, and a $300 incentive for a large boiler with 85% or better efficiency. Incremental costs for these measures are estimated at $360 and $1,800 respectively. The program would also offer a $150 incentive for a high-efficiency furnace and a $300 incentive for a high-efficiency gas package furnace; the incremental cost of both is $710. (UNS' response to Staff's data request JM 8.12 (see UNSG0463/04919); UNS' response to Staff's data request STF 12.17)

Q. Please describe the proposed Commercial Gas Cooking Efficiency program.

A. Incentives would be provided to operators of commercial kitchens, including business owners, schools and other government facilities, to install high-efficiency commercial gas cooking appliances. (Gary A. Smith testimony, p. 15; UNS' response to Staff's data request JM 8.12 (see UNSG0463/04913); UNS' response to Staff's data request STF 15.12)

Q. What would be the incentives offered by the Commercial Gas Cooking Efficiency program, and what would be the incremental costs of the high-efficiency gas cooking appliances covered by this program?

A. The cooking equipment covered under this program would include energy-efficient fryers, griddles and ovens. The incentives would range from $175 for a griddle, to $750 for Combination, Conveyor or Rotating Rack ovens. Incentives of $500 would be offered for Convection or Deck ovens and for high efficiency fryers. The full incremental costs of the covered equipment are estimated to range from $500 to $3,710 per unit. (UNS' response to Staff's data request JM 8.1 (see UNSG0463/04914); UNS' response to Staff's data request STF 12.20)

Q. How would UNS verify the installation of high-efficiency measures installed under its proposed DSM programs?

A. For the proposed DSM programs, the customer or contractor would be required to supply documentation relating to the purchase and installation of individual high-efficiency measures. In cases where such documentation could not be provided, UNS would perform on-site inspections. Energy efficiency ratings would be verified through manufacturers. Random on-site inspections may also be done in cases where documentation is provided, as a fraud prevention measure. With respect to the Residential New Construction Program, UNS or a UNS-approved contractor would conduct periodic inspections during construction and require documentation from the builder. (UNS' responses to Staff's data requests STF 12.9, 12.10, 12.16, 12.18 and 12.21)

Staff recommends that information regarding verification and inspection be provided by UNS for the LIW program in its program proposals.

Program Administration and Implementation

Q. How would UNS Gas administer its DSM programs?

A. UNS Gas would administer the Residential Furnace Retrofit and Commercial programs on an in-house basis, sharing these duties with UNS Electric in Mohave and Santa Cruz counties, in order to lower administrative costs. For the above three programs, external resources would be used for data entry, inspections and monitoring. For the Residential New Construction Program, UNS Gas and UNS Electric would administer the program in-house in Mohave County, including inspections; outside Mohave County UNS Gas would use external resources for data entry, inspections, builder training and monitoring. For the LIW program, UNS Gas handles payment processing and reporting in-house, while marketing and delivery is handled by outside agencies. (Testimony of Gary A. Smith, p. 18; UNS' responses to Staff's data requests JM 8.10, STF 12.16, STF 15.7 and JM 8. (see UNSG0463/04915, 04928, 04920))

Q. How would UNS Gas and UNS Electric apportion program costs for their jointly administered programs in Mohave and Santa Cruz counties?

A. Program costs would be apportioned according to the energy savings for each energy source. Program costs resulting in electric savings would be allocated to UNS Electric, while program costs resulting in gas savings would be allocated to UNS Gas. However, for Residential New Construction, where there are both gas and electric savings, program costs would be split equally between UNS Gas and UNS Electric. (UNS' response to Staff's data request JM 8.10)

Q. How would program costs for the Residential New Construction program be allocated in areas where UNS Electric is not the electric service provider?

A. In areas where UNS Electric is not the electric service provider, all program costs for the Residential New Construction program would be allocated to UNS Gas. (UNS' response to Staff's data request STF 12.14)

Q. Should UNS file a portfolio plan of its proposed DSM programs?

A. Yes. Staff recommends that UNS file a comprehensive DSM portfolio plan for Commission approval, along with detailed program proposals for each of the new DSM programs it wishes to pursue. Staff also recommends that UNS include, as part of its DSM portfolio filing, information for the LIW program, including data on cost-effectiveness. The filing could be made as soon as UNS has completed it. Staff encourages UNS to file a comprehensive DSM portfolio plan as soon as feasible, rather than waiting for the conclusion of the UNS Electric rate case.

Q. What should UNS include in its overall DSM portfolio plan?

A. The UNS DSM portfolio plan should discuss the portfolio plan itself, followed by program proposals including detailed discussions of each proposed DSM program. The filing should be as detailed as possible, because a high level of detail submitted for each DSM program may make it unnecessary for Staff, or others, to engage in a large amount of discovery. Specific items that should be submitted in the portfolio plan and program proposals include, but are not limited to, the following:

<u>Overall DSM Portfolio Plan</u>

(i) overall portfolio goals and objectives;

(ii) descriptions of all DSM programs to be included in the portfolio;

(iii) estimated levels of energy and capacity savings, utility costs, societal benefits and costs, and other benefits;

(iv) marketing plans;

(v) delivery plans, including implementation schedules;

(vi) measurement and evaluation plans;

(vii) description of the administration of the programs; and

(viii) proposed performance incentives (if any).

Individual DSM Program Proposals

(i) description and concept of the program;

(ii) program objectives and rationale;

(iii) target market segments and program eligibility;

(iv) estimate of baseline conditions;

(v) details on how the program works;

(vi) program products and services;

(vii) program delivery strategy;

(viii) program marketing and communications strategy plans;

(ix) specific DSM measures included in the program;

(x) annual program budget of utility costs broken down by categories, such as rebates and incentives, training, consumer education, marketing, planning and administration;

(xi) how the program is proposed to be funded;

(xii) program implementation schedule timeline;

(xiii) estimates of the anticipated level of program participation;

(xiv) estimated therm saving for each measure or program;

(xv) estimated societal costs of each measure or program, as appropriate;

(xvi) estimated societal benefits from the measure or program, as appropriate;

(xvii) other benefits of the measure or program, as appropriate;

(xviii) net benefits of the measure or program, as appropriate;

(xix) incremental costs for each DSM measure;

(xx) incentives or rebates to be offered (if any);

(xxi) the recipients of incentives or rebates (if any);

(xxii) number of DSM measures expected to be installed;

(xxiii) expected useful life of each unit; and

(xxiv) measurement, monitoring and evaluation procedures for each measure or program.

Monitoring and Evaluation

Q. Should monitoring and evaluation of each program be done, in addition to the verification (e.g., of proper installation) already discussed?

A. Yes. Monitoring can measure the impact of the entire DSM portfolio, to determine whether the resulting incremental benefits to society actually exceed the incremental costs. In addition, monitoring can measure the impact, if any, of each program, to determine whether the individual programs are cost-effective.

Q. What should UNS do if monitoring reveals that a program is not performing to expectations?

A. Monitoring would also allow UNS to refine, correct and modify DSM programs, in order to improve performance. Examples could include increasing or decreasing incentives, revising training programs where there are issues with installation, and broadening or narrowing the advertising programs to ensure that program marketing is effective.

Q. Should UNS terminate approved programs that are not performing to expectations, if modification of the program is not the answer?

A. Yes. If modifying a DSM program does not improve its performance sufficiently to meet the societal cost-effectiveness standard, or if UNS determines that, in its judgment, modification would not bring an under-performing program up to that standard, then UNS should terminate the program. Demand-side management resources should not be expended on ineffective programs.

Q. What should UNS do if it determines that a DSM program should be terminated?

A. First, UNS should inform Staff, in writing, of its decision to terminate a program, including its plans to notify participants, or potential participants. If a program is slated for termination, UNS should both notify participants and potential participants and honor any existing commitments. Existing commitments would include, but not be limited to, payment of incentives to program participants who have purchased energy equipment based on an understanding that their incremental costs would be offset by DSM incentives.

Q. What are Staff's recommendations regarding monitoring plans?

A. Staff recommends that UNS create a monitoring plan for each program and describe these plans in each program proposal.

Q. How should monitoring be conducted?

A. A representative sampling of participants should be monitored for programs with a large number of participants, tracking usage rates and the impact of DSM measures. For programs with smaller participation, most or all of the locations can be monitored to determine the impact of the programs. The impact of weather should be taken into account when monitoring and evaluating the cost-effectiveness of any DSM programs.

Q. How should Staff monitor UNS' DSM programs?

A. In addition to notifying Staff in writing and in advance of any decisions to terminate an approved DSM program, UNS should submit semi-annual reports including the following information:

(i) a brief description of the programs;

(ii) modifications to the programs made during the previous reporting cycle;

(iii) programs terminated during the previous reporting cycle;

(iv) modifications and/or terminations anticipated, if any, during the upcoming reporting cycle;

(v) number of participants, broken down by program;

(vi) number of new residences constructed or measures installed during the previous reporting cycle;

(vii) a description of monitoring activities;

(viii) an evaluation, based on data from monitoring, of each program's performance and cost-effectiveness during the previous reporting cycle;

(ix) therms saved by each program, during the previous reporting cycle;

(x) problems, if any, for each program and proposed solutions;

(xi) progress reports on any previously reported problems;

(xii) costs broken down by type; and

(xiii) research projects, if any, or any other significant information.

Semi-annual reports should be submitted within 60 days after the close of a reporting cycle (January-June and July-December). In addition, the Commission may review the programs in future rate cases.

Marketing and Advertisement of the UNS DSM Programs

Q. How would UNS' DSM programs be marketed and advertised?

A. The Residential Furnace Retrofit, the Commercial HVAC Retrofit and the Commercial Gas Cooking Efficiency programs would be marketed through brochures, bill inserts, customer relations with interest groups and trade market participants, print advertisements, website development (including Energy Advisors), media promotions, presence at conferences and public events and presentation to customers and/or trade allies. The Residential New Construction program would be marketed through brochures for new home purchasers, customer relations with builders, developers and sub-contractors and presentations to developers and trade allies. There would also be training or education seminars tailored to assist participants with the procedural or technical aspects of each program. (Gary A. Smith testimony, pp. 13 and 15; UNS' response to Staff's data request JM 8 (see UNSG0463/04927, 04924, 04914 and 04919))

Marketing of the enhanced LIW program, including the emergency bill assistance component, would be done by the outside agencies currently administering the program. (UNS' response to Staff's data request STF 15.9) Staff recommends that UNS provide more detailed information regarding marketing of LIW in its program proposal.

Cost Recovery of DSM Programs

Q. What is UNS' proposed funding for the entire DSM portfolio?

A. UNS has proposed total funding of $1,051,616 for its DSM programs, including the $21,600 non-DSM emergency bill assistance component of LIW.

Q. What are the alternatives for the recovery of DSM program costs?

A. The alternative methods for recovering the cost of DSM programs include the following: (1) a deferral account with base rate amortization; (2) through base rates with no deferral accounting; and (3) through a PGA.

Q. Should UNS recover its DSM costs through a deferral account with base rate amortization?

A. No. With a deferral account, approved DSM costs are placed in the account to be considered for base rate cost recovery during the next rate case; during the interim, these costs may earn interest. The bank balance, with interest, can result in a major cost that must be resolved during that next rate case. Another disadvantage to a deferral account is that it would not permit timely recovery of DSM costs.

Q. Should UNS recover its DSM costs directly through base rates with no deferral accounting?

A. No. Cost recovery through base rates is current, but inflexible. DSM spending could not be changed between rate cases, so that spending for programs could not be increased or decreased, as needed. In cases where DSM activities were eliminated, this method of cost recovery would leave the DSM funding in place, continuing to collect funds for defunct activities until the next rate case.

Q. Should UNS recover its DSM costs through its PGA?

A. No. While cost recovery would be timely and changes in spending could be made without a rate case, inclusion of DSM charges would complicate administration of the PGA and would potentially decrease transparency regarding both gas costs and the DSM charge. Utilizing this mechanism would also exempt transportation-only customers from paying the DSM charge.

Q. How should UNS recover its costs for its DSM programs?

A. Staff recommends that UNS recover its costs for its DSM programs through a separate DSM adjustment mechanism. A DSM adjustor does not bypass transportation-only customers and provides the advantages of timely cost recovery and flexibility, without complicating administration of the PGA. Another advantage is that a separate DSM adjustor provides more transparency to ratepayers regarding the cost of DSM programs.

Q. How does UNS propose to recover its DSM costs for its new, proposed DSM programs?

A. UNS proposes to recover its costs through an annually adjusted DSM per therm charge. Initially, the DSM charge would be based on DSM annual funding divided by test year therm sales. For example, if UNS' proposed $1,051,616 in funding were approved, it would be divided by 138,233,864 in test year therm sales, to arrive at a $0.007608 per therm charge. (However, Staff recommends that the entire proposed funding not be initially included, as discussed later in this testimony.) In following years, the per therm charge would be based on the requested funding, adjusted for the previous year's over- or under-collection, divided by the projected therm sales. (Tobin L. Voge testimony, p. 18; UNS' response to Staff's data request JM 8.11)

Q. Would cost recovery for the LIW program be treated the same as cost recovery for the other DSM programs in the DSM portfolio?

A. Yes. UNS proposes that the enhanced and reclassified LIW program be funded through the DSM per therm charge. (Gary A. Smith testimony, p. 13; Tobin L. Voge testimony, p. 18)

Q. What costs should UNS be able to recover?

A. UNS should recover the program costs associated with approved DSM projects. These costs include administrative costs, marketing and promotional costs; the cost of incentives, such as rebates; the cost of training associated with DSM programs; and the cost of verifying proper installation and construction.

Q. How would the per therm DSM charge be adjusted each year?

A. Within the DSM portfolio account would be subaccounts for each DSM program where the costs for each DSM program would be separately recorded. By January 31 of each year, UNS would file with the Commission to set the per therm DSM adjustment charge. UNS would provide the documented costs for each subaccount and provide the revenue received from ratepayers through the per therm DSM charge for the previous year. The per therm charge for the next year would be calculated by dividing the account balance by the projected therms for the upcoming year, also adjusting for over- or under-collection. (Schedule 1, Staff Example of DSM Adjustor Calculation)

Q. Which programs should UNS fund using the DSM adjustment mechanism, and when should funding begin?

A. Staff recommends that all DSM programs be funded through the DSM adjustment mechanism, minus the $21,600 LIW emergency bill component. However, initially, only funding for the LIW program should be included in the DSM adjustor; without the emergency bill component, the initial budget would be $113,400 ($135,000 - $21,600). Funding for new DSM programs should not be included in the DSM adjustor at this time. Therefore, Staff recommends that the initial funding be $0.00082 per therm ($113,400 ÷ 138,233,864). The DSM charge would be reset annually on March 1, following the UNS January filing.

Q. What if the LIW program does not appear to be cost-effective?

A. Program elements can be revised to improve cost-effectiveness and remedy or mitigate any other problems with the program. Non-quantifiable societal benefits can be taken into account in evaluation of a program.

Q. How would customers pay for the cost of DSM programs?

A. Customers would pay for the DSM costs, based on therm usage, using a separate line item included on customer bills. (UNS' response to Staff's data request STF 12.5)

Q. What would be the effect of the DSM charge on customer bills?

A. UNS proposes a per therm charge of $0.007608 for its DSM program, including the non-DSM emergency bill assistance component in the LIW program. Under this proposal, residential customers using the July average (for all residential customers) of 15 therms would see a DSM adjustor charge of $0.11; residential customers using the January average of 87 therms (for all residential customers) would see a DSM adjustor charge of $0.66. The per therm charge, based on the entire UNS DSM proposed budget, minus the $21,600 emergency bill assistance component, would be $0.007451. At this level, a residential customer using the July average of 15 therms would still see a DSM charge of $0.11, while customers using the January average of 87 therms would see a DSM charge of $0.65. Staff's recommendation of a an initial DSM charge of $0.00082 per therm would result in a 1 cent charge, while at the January average of 87 therms customers would see a 7 cent charge.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. UNS should continue to work toward expanding participation in the CARES program to additional eligible households.
2. The CARES program monthly customer charge should remain at its current level, and the current per therm discount should be retained.
3. The deferred account for the CARES program should be discontinued.
4. UNS should submit detailed DSM program proposals to the Commission as soon as possible, rather than waiting for the conclusion of the UNS Electric rate case.
5. Emergency bill assistance should not be included in the DSM portfolio. Emergency bill assistance, in the amount of $21,600, should be funded from base rates and combined, as an additional funding source, with the existing Warm Spirit emergency bill assistance program.
6. UNS should file a comprehensive DSM portfolio plan for Commission approval, along with detailed program proposals for each of the new DSM programs it wishes to pursue.
7. When filing its detailed DSM program proposals, UNS should include the data required to calculate the cost-effectiveness of each program on a Societal Test basis.
8. As part of its DSM portfolio filing, UNS should provide information for the LIW program, including marketing, verification and inspection, and cost-effectiveness.

9. UNS should create a monitoring plan for each DSM program and describe these plans in each program proposal.

10. UNS should submit semi-annual DSM reports.

11. UNS should recover its costs for all of its DSM programs through a separate DSM adjustment mechanism. The initial DSM charge, to fund the ongoing LIW program, should be set at $0.00082 per therm.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ATTACHMENT A

STAFF HYPOTHETICAL EXAMPLE OF DSM ADJUSTER MECHANISM CALCULATION

FIRST YEAR DSM ADJUSTER	**A**	**B**	**C**	**D**	**E**	**F**	**G**
	ADJUSTED TEST YEAR THERMS	DSM BUDGET	PER THERM DSM CHARGE (B ÷ A)	THERMS SOLD	DSM REVENUE COLLECTED (C X D)	EXPENDITURES	(OVER)/UNDER DSM COLLECTION-BALANCE
	138,233,864	$500,000	$0.003617	140,000,000	$506,380	$600,000	$93,620

$500,000 ÷ 138,233,864 = $0.003617
$0.003617 X 140,000,000 = $506,380
$600,000 - $506,380 = $93,620

SECOND AND SUCCEEDING YEARS	**A**	**B**	**C**	**D**	**E**
	(OVER)/UNDER DSM COLLECTION BALANCE (=G, ABOVE)	DSM BUDGET	DSM BUDGET ADJUSTED FOR (OVER)/UNDER COLLECTION (B + OR – A)	PROJECTED THERM SALES	PER THERM DSM CHARGE (C ÷ D)
	$93,620	$900,000	$993,620	145,000,000	$0.006853

$93,620 + $900,000 = $993,620
$993,620 ÷ 145,000,000 = $0.006853

Note: all numbers, except adjusted test year therms, are hypothetical.

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
CHAIRMAN
WILLIAM A. MUNDELL
COMMISSIONER
MIKE GLEASON
COMMISSIONER
KRISTIN K. MAYES
COMMISSIONER
GARY PIERCE
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC., DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC	DOCKET NO. G-04204A-05-0831

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION

UTILITIES DIVISION STAFF

FEBRUARY 9, 2007

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ATTACHMENTS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NOS. G-04204A-06-0463 ET AL

My testimony addresses the following issues:

- The Company's proposed revenue requirement.
- Adjustments to test year data
- Rate base, including construction work in progress
- Test year revenues (including number of customers and usage) and expenses.
- Depreciation rates
- Rules and regulations, including line extensions.

My findings and recommendations for each of these areas are as follows:

- The Company's proposed revenue requirement of a base rate increase of $9.647 million is overstated. I recommend that UNS Gas be authorized a base rate increase of $4.721 million.

- The following adjustments to UNS Gas' proposed original cost and fair value rate base should be made:

Summary of Staff Adjustments to Rate Base

Adj. No.	Description	Original Cost Increase (Decrease)	Fair Value Increase (Decrease)
B-1	Remove Construction Work in Progress	$ (7,189,231)	$ (7,189,231)
B-2	Remove GIS Deferral	$ (897,068)	$ (897,068)
B-3	Cash Working Capital - Lead/Lag Study	$ 770,960	$ 770,960
B-4	Accumulated Deferred Income Taxes	$ 195,336	$ 195,336
	Total of Staff Adjustments	**$ (7,120,003)**	**$ (7,120,003)**
	UNS Proposed Rate Base	$ 161,661,361	$ 191,177,715
	Staff Proposed Rate Base	**$ 154,541,358**	**$ 184,057,712**

- The following adjustments to UNS Gas' proposed revenues, expenses and net operating income should be made:

Summary of Staff Adjustments to Net Operating Income

Adj. No.	Description	Increase (Decrease)
C-1	Revenue Annualization	$ 62,896
C-2	Weather Normalization	$ 1,205
C-3	Adjustment to Bad Debt Expense	$ (776)
C-4	Remove Depreciation & Property Taxes for CWIP	$ 222,981
C-5	Remove Amortization of Deferred GIS Cost	$ 183,606
C-6	Incentive Compensation and SERP	$ 164,204
C-7	Emergency Bill Assistance Expense	$ (13,263)
C-8	Remove Nonrecurring Severance Payment Expense	$ 32,167
C-9	Overtime Payroll Expense	$ 75,531
C-10	Payroll Tax Expense	$ 8,201
C-11	Nonrecurring FERC Rate Case Legal Expense	$ 190,992
C-12	Property Tax Expense	$ 49,300
C-13	Worker's Compensation Expense	$ 21,020
C-14	Membership and Industry Association Dues	$ 16,498
C-15	Fleet Fuel Expense	$ 32,199
C-16	Postage Expense	$ 70,671
C-17	Interest Synchronization	$ 118,085
Total of Staff's Adjustments to Net Operating Income		**$ 1,235,516**
	Adjusted Net Operating Income per UNS Gas	$ 8,428,981
	Adjusted Net Operating Income per Staff	**$ 9,664,497**

- The new depreciation rates proposed by UNS Gas presented in Dr. White's direct testimony Attachment REW-2 should be adopted for use in this case. The depreciation rates proposed by UNS Gas were developed in a manner that is consistent with the Commission's rules for depreciation rates.

- Each of the new depreciation rates proposed by UNS Gas should be clearly broken out between (1) a service life rate and (2) a net salvage rate. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

- The Company's proposed changes to Rules and Regulations in its tariff should be adopted, as discussed in my testimony.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst (CRRA). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts (SURFA). I have also been a member of the

American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 27 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorney generals, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Washington, Washington D.C., and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified before the Commission previously on a number of occasions. Most recently, I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS" or "Company"), and concerning APS's proposed depreciation rates in Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, a proceeding involving APS base rates and other matters.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the revenue requirement and selected other issues, including new depreciation rates, and rules and regulation changes proposed by UNS Gas, Inc. ("UNS Gas") in the current rate case.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 through RCS-6 contain the results of my analysis and copies of selected documents that are referenced in my testimony.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

Q. What revenue increase has been requested by UNS Gas?

A. UNS Gas is requesting a revenue increase of $9.647 million, or approximately 7 percent. UNS Gas witness James Pignatelli's direct testimony at pages 2-3 attributes the need for the requested increase primarily to increased growth in UNS Gas' service territory and the related increases in capital expenditures and operating costs.

Q. What revenue increase does Staff recommend?

A. Staff recommends a revenue increase of $4.721 million.

A. Test Year

Q. What test year is being used in this case?

A. UNS Gas' filing is based on the historic test year ended December 31, 2005. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are annualized based on end of test year levels. This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

B. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-4 and net operating income adjustment Schedules C-1 through C-17.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. The schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on Staff's proposed Original Cost and Fair Value rate bases. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return on original cost rate base of 8.12%, as presented in the prefiled testimony of Staff witness Parcell, is provided on Schedule D for convenience. Schedule D uses the capital structure and cost rates recommended in the prefiled testimony of Mr. Parcell. The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the income deficiency by the gross revenue conversion factor (GRCF). The derivation of the GRCF is shown on Schedule A-1.

Q. What is shown on Schedule B?

A. Page 1 of Schedule B presents UNS Gas's proposed adjusted test year Original Cost and Fair Value rate base and Staff's proposed adjusted test year Original Cost and Fair Value rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically UNS Gas Schedule B-1. Staff's recommended adjustments to rate base are summarized on Schedule B.1.

Q. How was the fair value basis of rate base determined?

A. The Fair Value basis was determined by averaging Original Cost and reconstruction cost new depreciated (RCND) information.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is UNS Gas's adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to UNS Gas's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments are discussed in this testimony. Schedules C-1 through C-17 provide further support and calculations for the net operating income adjustments I am recommending.

Q. What did your review of UNS Gas' filing indicate?

A. As shown on Schedule A, based on the rate of return recommended by Staff witness Parcell and the adjustments to UNS Gas' rate base and net operating income recommended by myself and other Staff witnesses, I have calculated a revenue requirement deficiency of $4.721 million for UNS Gas.

III. RATE BASE

Q. Have you prepared a schedule that summarizes staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to UNS Gas' proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis are presented below:

Summary of Rate Base	UNS Gas	Staff	Difference
Original Cost Rate Base	$ 161,661,361	$ 154,541,358	$ (7,120,003)
Fair Value Rate Base	$ 191,177,715	$ 184,057,712	$ (7,120,003)

B-1, Construction Work in Progress

Q. Please explain the adjustment shown on Schedule B-1.

A. UNS Gas has proposed to include $7.189 million of Construction Work in Progress (CWIP) in rate base. Staff adjustment B-1 removes that amount of CWIP from rate base.

Q. Please discuss UNS Gas' reasons for requesting the inclusion of CWIP in rate base.

A. As described in the testimony of UNS Gas witness Kentton Grant, the Company believes that inclusion of CWIP in rate base is necessary to preserve the financial integrity of the Company. Mr. Grant indicates that, as reflected in the Company's rate application, rate base treatment of the $7.189 million test year CWIP balance provides UNS Gas with approximately $1.5 million in additional annual revenues. He states that denial of this requested rate treatment would have a material adverse impact on the Company's rate relief and future earnings, and would make it difficult for the Company to attract new capital on reasonable terms. The Company has been experiencing robust growth and expects to need access to outside capital to fund system growth and capital improvements. Mr. Grant also states that inclusion of CWIP in rate base is one of the few available tools to help mitigate the effects of regulatory lag. He suggests further that, by including CWIP in rate base in this proceeding, the time period between this rate case and the next rate filing by UNS Gas will hopefully be extended. He indicates that if the Company's proposed rate base treatment of CWIP is denied, the authorized rate of return should be increased, and the Commission should consider an adjustment for plant placed into service after the test year. He points out that the Commission has, on occasion, allowed the inclusion of post test year plant in rate base.

Q. Is inclusion of CWIP in rate base up to the discretion of the Commission?

A. Yes, it is. Staff's understanding is, in specific instances, the Commission has allowed a utility to include CWIP in rate base, but the Commission's general practice has been to not allow CWIP to be included in rate base.

Q. Does Staff agree with the proposal of UNS Gas to include CWIP in rate base in the current case?

A. No. In general, Staff does not favor inclusion of CWIP in rate base unless the utility demonstrates compelling reasons to justify this exceptional ratemaking treatment. For a number of reasons, including the following, Staff does not support UNS Gas' request for rate base inclusion of CWIP in the current case:

1) Inclusion of CWIP in rate base is an exception to the Commission's normal practice, and UNS Gas has not met its burden of proof showing why it requires such an exceptional ratemaking treatment.

2) The CWIP was not in service at the end of the test year. As of December 31, 2005, the construction projects were not serving customers.

3) The Company has not demonstrated that its December 31, 2005 CWIP balance was for non-revenue producing and non-expense reducing plant. Much of the construction appears to be for mains, services and meters related to serving customer growth, i.e., to be revenue producing. Test year revenues have been annualized to year-end customer levels. However, revenues have not been extended beyond the test year to correspond with customer growth. Hence, including the investment in rate base, without recognizing the incremental revenue it supports, would be imbalanced.

4) While the Company has stated that inclusion of CWIP in rate base could result in deferring the filing of its next rate case, the Company has made no specific enforceable commitments to a filing moratorium period.

Q. Please elaborate on how including CWIP in rate base is an exceptional ratemaking treatment and why the circumstances in this case do not warrant such treatment.

A. CWIP, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it was not used or useful in delivering gas service to the Company's customers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. The ratemaking process therefore excludes CWIP from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current UNS Gas rate case, the test year is calendar 2005, and the construction projects the Company seeks to include in rate base were not providing service during that period. As a general ratemaking principle, such CWIP should be excluded from rate base.

Furthermore, some of the facilities that are being constructed and are included in CWIP will be used subsequent to the 2005 test year to serve additional customers. It would not be appropriate to include the investment that will serve those new customers without also including the revenues that would be received from those customers. In other words, allowance of CWIP in rate base would result in a mismatch in the ratemaking process. Additionally, some of the plant being added, such as main replacements, could result in a reduction in maintenance expenditures which would not be reflected in the test period. The inclusion of CWIP in rate base, therefore, creates an imbalance in the relationships between rate base serving customers and the revenues being provided to the utility from customers who were taking service during the test year. Consequently, CWIP should not be allowed in rate base unless there are very compelling circumstances which would warrant an exception to the general rule. In the current case, UNS Gas has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding CWIP from rate base. It is not appropriate to include the CWIP in rate base, particularly as the projects may result in additional revenues or cost savings which have not been reflected in the 2005 test year.

Q. How does UNS Gas accrue a return on construction projects?

A. UNS Gas accrues a return, representing its financing costs during the construction period, called Allowance for Funds Used During Construction (AFUDC). This AFUDC return accounts for the utility's financing cost during the construction period. Then, when the plant is placed into service, the AFUDC becomes part of the cost of the plant and is depreciated.

Q. How does plant that is placed into service between rate case test years typically get reflected in the regulatory process?

A. If the plant is used to serve new customers, the utility receives revenue from those customers. If the plant helps the utility reduce expenses, such as maintenance, the utility benefits from such cost reductions during the intervening period. Once the plant is recognized in rate base in a test year, and rates are reset, the utility earns a cash return on the plant investment, less accumulated depreciation. The related revenues and expense impacts, including known and measurable expense reductions enabled by the plant, are then also recognized in the ratemaking process.

Q. Does Staff agree with UNS Gas' alternative proposal to include post-test year plant additions in rate base, if the inclusion of CWIP in rate base is denied?

A. No. For similar reasons to those described above, Staff does not agree with UNS Gas' proposed alternative of including post-test year plant in rate base.

Q. Is another witness for Staff addressing certain aspects of UNS Gas' request for inclusion of CWIP in rate base?

A. Yes. Staff's rate of return witness, Dave Parcell, is addressing the determination of a fair rate of return that would allow UNS Gas to attract new capital on reasonable terms. In making his cost of capital recommendations, Mr. Parcell has been made aware of and has taken into consideration UNS Gas' proposal to include CWIP in rate base and Staff's recommendation that CWIP not be included in rate base in this case.

Q. Does Staff's adjustment to remove CWIP from rate base affect UNS Gas's expenses?

A. Yes. UNS Gas had proposed to treat CWIP at the end of the test year as if it were plant in service. Consistent with that, UNS Gas proposed increases to depreciation and property tax expense. Consistent with Staff's recommendation that CWIP not be included in rate base, Staff adjustment C-4, which is described in a subsequent section of my testimony, removes the related UNS Gas adjustments for depreciation and property tax expense.

<u>B-2, Global Information System (GIS) Deferral</u>

Q. Please explain the adjustment shown on Schedule B-2.

A. UNS Gas has proposed to include $897,068 in rate base for a deferral of costs related to its Geographic Information System (GIS). Staff adjustment B-2 removes that amount of deferred costs from rate base.

Q. What functions and benefits does the UNS Gas GIS provide?

A. UNS Gas witness Gary Smith's direct testimony at pages 6-7 indicates that the GIS helps UNS Gas maintain an accurate, up-to-date record of its facilities. His testimony also indicates that the GIS helps the Company comply with state and federal laws and provides numerous benefits to the Company and its customers including:

- Maintaining accurate maps of facilities
- Improving response time
- Promoting better-informed decisions
- Facilitating faster completion of map changes and more timely reporting of facility assets
- Enabling employee field access of up-to-date GIS maps, allowing them to locate lines more quickly and accurately.

Q. Please describe how UNS Gas has accounted for costs related to its GIS.

A. As described in the Company's response to RUCO data request 2.15[1], the UNS Gas' GIS entered service on July 1, 2001. The GIS resides in Account 391 per the FERC Uniform System of Accounts (USOA). The original cost of the GIS was $1,158,035 and has been depreciated at a rate of 13.92% per year[2]. This part of the Company's accounting is not controversial.

However, the Company's proposal to add $897,068 in a pro forma adjustment to rate base for a subsequent questionable deferral of costs related to its GIS and to prospectively amortize such a deferred cost over a three-year period is controversial, and has been determined by Staff to be inappropriate, as described below.

[1] Copies of UNS Gas' responses to data requests referenced in my testimony are provided in Attachment RCS-5.
[2] UNS Gas has depreciated Account 391.20, Computer Equipment – Desktop PCs, at 13.89 percent per year. In the current case, UNS Gas is proposing a five-year amortization for that account. Staff has not taken exception to this UNS Gas request.

Q. Please describe how the deferral of costs related to the UNS Gas GIS occurred, and how UNS Gas' deferral accounting for such costs was ultimately determined, by the Company itself, to be inappropriate.

A. During 2003-2005, UNS Gas undertook a project to locate and assign global positioning system (GPS) information to its existing service lines in order to update the UNS Gas GIS. The project was undertaken as a result of an Arizona Corporation Commission compliance audit, which found that: "Maps available at the time of the audit and used by locating, leak survey, construction and emergency personnel fail to include all service lines." As explained in UNS Gas witness Gary Smith's testimony, at page 6, a 2002 Annual Commission Pipeline Safety Audit had concluded that the Company needed to complete mapping of its service lines in a more timely basis. The Company enlisted outside contractors to help it comply with this recommendation

UNS Gas initially accounted for these costs as capital costs. The Company partially placed the project into service in 2005, but assigned it an in-service date of 12/31/03, with catch-up depreciation of approximately $50,000 recognized as of 8/31/05. The total cost of the project was approximately $897,000, with 83% of the cost, or $747,000, paid to Front Line Energy for locating and "GPS-ing" the lines.

In 2005, UNS Gas concluded that, absent an ACC order to defer such costs, the accounting treatment of the costs would need to be consistent with Generally Accepted Accounting Principles (GAAP). The FERC USOA does not specifically prescribe a procedure to be used in accounting for the costs of developing computer software. However, FERC issued an Order on Accounting for Pipeline Assessment Costs in Docket No. A105-1-000 on 6/30/05, which contained a specific reference to the AICPA's Accounting Standards Executive Committee (AcSEC) Statement of Position ("SOP") 98-

1, Accounting for the Costs of Computer Software Developed or Obtained for Internal Use ("SOP 98-1"). Paragraph 22 of SOP 98-1 states, in pertinent part that:

> "The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the data in the new system, creation of new/additional data, and conversion of old data to the new system. Data conversion often occurs during the application development stage. Data conversion costs, except as noted in Paragraph 21, should be expensed as incurred."[3]

As a result of this interpretation by UNS Gas of the proper accounting, the Company determined that certain misstatements of the financial statements as of December 31, 2004 had occurred. These included an overstatement of Total Utility Plant of $872,000 and an understatement of cumulative Other Operations and Maintenance of $872,000.

Q. Please discuss UNS Gas' reasons for requesting the inclusion of the GIS costs in rate base.

A. As explained in the testimony of UNS Gas witness Gary Smith and in the Company's workpapers for the adjustment, UNS Gas is asking to recover a return on and a return of this investment because the expenditures were made to insure compliance with ACC requirements and provide benefits to present and future ratepayers of the utility.

Q. Please discuss Staff's reasons for removing the GIS cost from rate base.

A. This cost was required to be expensed under GAAP. It is of a one-time, non-recurring nature. Had it been expensed properly by UNS Gas in the appropriate periods, the vast majority of the GIS cost that UNS Gas deferred would have been expensed prior to the

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[3] Emphasis as supplied in UNS Gas' October 3, 2005 Memo to File re 2003-05 UNS Gas "GPS and Locate" Costs. See Attachment RCS-5.

2005 test year. UNS Gas did not request Commission pre-approval for recovery or cost deferral, and therefore could not defer the costs as a regulatory asset.

The majority of the cost that UNS Gas is requesting was incurred prior to the 2005 test year, and should have been expensed by the Company in periods prior to 2005. In the UNS Gas memo dated October 3, 2005, which I have reproduced in Attachment RCS-5, the Company concluded (at memo page 4 of 7) that "the misstatements to the 2003 and 2004 UNS income statements are deemed to be immaterial" and "the misstatements to the December 31, 2004 balance sheets are deemed to be immaterial as the misstatement to Total Utility Plant was .02% and to Total Assets of .03%" At page 5 of 7 of that memo, the Company concludes that: "Due to the immateriality of the error to UNS, we do not believe that the error masks a change in earnings, does not hide a failure to meet analysts' consensus expectations for the enterprise, it does not change income to a loss, it does not affect compliance with regulatory requirements, it did not increase management compensation and does not conceal an unlawful transaction." At page 7 of 7 of the memo, the Company concludes that: "We have carefully considered both quantitative and qualitative aspects of the misstatement of the UNS Gas 'GPS and Locate' costs and believe that the error is not material to the respective financial statements for all periods considered. Accordingly, it is deemed acceptable to record the correcting adjustment in the third quarter of 2005." In the third quarter of 2005, UNS Gas recorded an adjustment to remove the deferred costs from its balance sheet and to charge them to operating expenses.

Based on a review of the Company's October 3, 2005 memo and the supporting documentation provided by UNS Gas, Staff concludes that the deferred GIS costs requested by UNS Gas are not an appropriate rate base item, do not qualify as a "regulatory asset," were not pre-approved for deferral by the Commission, are non-recurring costs that should have largely been expensed by the Company in periods prior to the 2005 test year, and therefore are not appropriate to include in test year rate base.

Q. Does Staff have a related adjustment to UNS Gas's expenses?

A. Yes. UNS Gas had proposed to amortize the deferred GIS cost over three years. As explained in more detail in a subsequent section of my testimony, Staff adjustment C-5 removes that amortization expense.

<u>B-3, Cash Working Capital</u>

Q. Have you reviewed the Company's request for a working capital allowance?

A. Yes. The Company's working capital request consists of three separate subcomponents. The subcomponents are: (1) a negative cash working capital balance of $3.281 million based on a lead/lag study; (2) a thirteen-month average materials and supplies balance of $2.040 million; and (3) a thirteen-month average prepayments balance of $195,942. As shown on Company Schedule B-5, UNS Gas' rate base reflects a request for working capital of negative $1.045 million. I will address the Company's cash working capital request, along with the lead/lag study UNS Gas provided as support for that request.

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does UNS Gas have a positive or negative cash working capital requirement?

A. UNS Gas has a negative cash working capital requirement. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company. On average, revenues from ratepayers are received prior to the time when the utility pays the associated expenditures.

Q. Did UNS Gas present a lead/lag study in support of its cash working capital requirement?

A. Yes, UNS Gas performed a lead/lag study to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with the work papers provided in the case.

Q. Has UNS Gas made any revisions to the cash working capital calculation included in its filing?

A. Yes. According to the response to data request STF 5.76[4], there was an error in the cash working capital schedule in the Company's filing. Specifically, UNS Gas's response to STF 5.76 indicated that at Company Schedule B-5, line 19, "Revenue Taxes and Assessments" the amount should be $11,966,406 as opposed to $18,788,535. This Company-identified correction would change the balance of negative cash working capital from $3,280,866 to $2,586,909, increasing rate base by $693,957.

[4] A copy of this response is provided in Attachment RCS-5.

A related impact on income taxes also affects the amount of cash working capital allowance that is deducted from rate base.

Q. Are you recommending any revisions to UNS Gas' cash working capital request?

A. Yes. As mentioned above, I have reflected UNS Gas's corrected cost amounts in my cash working capital calculation. I have also reflected the impact of Staff's adjustments to operating expenses, impacts on gas costs related to Staff's sales adjustments, and impacts on revenue based taxes. I have also synchronized the calculation with cash working capital with Staff's recommended revenue increase.

Q. What is the result of your cash working capital calculation?

A. As shown on Schedule B-3, UNS Gas' filed cash working capital request should be increased by approximately $771,000. UNS Gas's proposed cash working capital of negative $3.281 million should be increased to negative $2.510 million.

B-4, Accumulated Deferred Income Tax

Q. Please explain the adjustment to Accumulated Deferred Income Taxes ("ADIT").

A. This adjustment is shown on Schedule B-4, and increases rate base by $195,336 for the impact of the following:

1) removal of the ADIT related to the GIS deferral that UNS Gas added to rate base that was removed by Staff[5];

2) removal of the ADIT related to the Supplemental Executive Retirement Plan ("SERP")[6]; and

3) removal of 50 percent of the ADIT related to incentive compensation[7].

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[5] See Staff Adjustment B-2, discussed above.
[6] Also see Staff Adjustment C-6 that has removed the expense related to SERP.
[7] Staff adjustment C-6 allocates the cost of incentive compensation 50/50 between shareholders and ratepayers.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Schedule C, page 1, summarizes Staff's recommended net operating income. Schedule C.1, present Staff's recommended adjustments to test year revenues and expenses on an Arizona jurisdictional basis. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. UNS Gas's proposed adjusted test year net operating income is $8.429 million, whereas Staff's recommended adjusted net operating income is $9.664 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1, Revenue Annualization

Q. Please explain Staff Adjustment C-1.

A. This adjustment presents Staff's revenue annualization. UNS Gas included a revenue annualization with its filing. The revenue annualization adjusts revenues to reflect the growth in customers that occurred throughout the test year. The customer level is annualized to year-end. In Staff's calculation December 2005 customers were used. The difference between actual December 2005 customers, by rate class, and the number of customers in each of the other months of the test year was identified. The change in customers to an annualized year-end level was then multiplied by the customer charge and margin amounts applicable to that rate class. In this adjustment, Staff used the same customer charge and margin amounts used by UNS Gas. As shown on Schedule C-1, Staff's revenue annualization adjustment resulted in $102,433 more gas revenue (excluding purchased gas) than did the revenue annualization proposed by UNS Gas.

C-2, Weather Normalization

Q. Please explain the adjustment for weather normalization.

A. This adjustment increases retail revenue by $1,962. Staff's adjustment varies from the weather normalization adjustment proposed by UNS Gas because the weighted average number of customers, in Staff's annualization, exceeded the corresponding level reflected in UNS Gas' corresponding annualization. Both the Staff and the UNS Gas weather normalization adjustments reflect an increase to revenue because the test year was warmer than normal. The details of Staff's adjustment are shown on Schedule C-2.

C-3, Bad Debt Expense

Q. Please explain the adjustment for bad debt expense.

A. This adjustment increases bad debt expense by $1,263. It is impacted by the higher annualized and normalized revenue levels derived by Staff in Adjustments C-1 and C-2, as well as higher total gas costs associated with the higher annualized gas sales volumes.

Q. How were uncollectibles related to the Company's collection of gas costs reflected in Staff's calculation?

A. Uncollectibles related to PGA revenue and to the gas cost recovered in base rates have traditionally been an operating expense for purposes of determining the utility's base rate revenue requirement. Under the Company's and Staff's proposals, UNS Gas would recover its gas costs fully through the PGA. For purposes of Staff's revenue requirement calculation, I have included gas cost-related uncollectibles in the determination of operating expenses.

Q. Do you agree with the Company's derivation of the uncollectibles factor?

A. Yes. Both Staff's and the Company's pro forma adjustment for bad debt expense use the two-year average uncollectibles factor calculated by the Company of 0.51052%. This same uncollectibles factor is also used in the gross revenue conversion factor shown on Schedule A-1.

C-4, Remove Depreciation and Property Taxes for CWIP

Q. Please explain Staff Adjustment C-4.

A. This adjustment removes the pro forma amounts calculated by UNS Gas for depreciation and property taxes related to the Company's proposal to include CWIP in rate base. As explained above[8], Staff disagrees with that Company proposal to include CWIP in rate base. Accordingly, Staff has also removed the pro forma depreciation and property tax expense adjustments proposed by UNS Gas. As shown on Schedule C-4, this reduces the Company's proposed expenses by $363,150.

C-5, Remove Amortization of Deferred GIS Cost

Q. Please explain Staff Adjustment C-5.

A. This adjustment removes the Company's proposed amortization of $299,023. As explained above in conjunction with Staff Adjustment B-2, during 2003-2005, UNS undertook a project to locate and assign global positioning system (GPS) information to its existing service lines in order to update the UNS Gas GIS. Part of the basis for this request by the Company is that the project has benefit to future periods. However, these expenses largely were incurred in prior periods and are nonrecurring. Without seeking Commission pre-approval, UNS Gas is now requesting deferral treatment for costs that should have been expensed in periods prior to the test year.

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[8] See above discussion in conjunction with Staff Adjustment B-1.

Staff agrees with the portion of UNS Gas' adjustment that removes the non-recurring GIS costs from test year O&M expense.

Staff disagrees, however, with the Company's proposal to amortize such costs prospectively over a three-year period. UNS Gas is requesting a return of those prior-year costs plus related costs incurred during 2005, for the GIS project over a three-year period via its proposed amortization. Had it been expensed properly by UNS Gas in the appropriate periods, the vast majority of the GIS cost that UNS Gas deferred would have been expensed prior to the 2005 test year. As noted above, UNS Gas did not request Commission pre-approval of recovery, and could therefore not defer the costs as a regulatory asset. As explained above in conjunction with Staff Adjustment B-2, Staff disagrees with UNS Gas' proposed deferral treatment of such costs. Staff's rate base adjustment B-2 removed the deferred balance from rate base. Staff's Adjustment C-5 removes the related Company proposed amortization. This adjustment reduces UNS Gas' proposed amortization expense by $299,023.

C-6, Incentive Compensation and Supplemental Executive Retirement Program

Q. Please explain Staff Adjustment C-6.

A. This adjustment removes 50% of the expense related to the various incentive compensation programs in effect at UNS Gas and 100% of the expense for the Supplemental Executive Retirement Plan (SERP). In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50% of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. Please discuss the UniSource Energy Corporation's Performance Enhancement Program.

A. As explained in the Company's supplemental response to data request STF 5.72, UNS Gas' non-union employees participate in UniSource Energy Corporation's Performance Enhancement Program ("PEP"). UniSource Energy Services ("UES") is a subsidiary of UniSource Energy Corporation and the parent company of UNS Gas. The structure of the PEP determines eligibility for certain bonus levels by measuring UES' performance in three areas: (1) financial performance; (2) operational cost containment; and (3) core business and customer service goals. Levels of achievement in each area are assigned percentage-based "scores." Those scores are combined to calculate the final payout. The amount made available for bonuses pursuant to the PEP formula may range from 50 percent to 150 percent of the targeted payment level. The financial performance and operational cost containment components each make up 30 percent of the bonus structure, while the core business and customer service goals account for the remaining 40 percent.

As explained in the Company's supplemental response to data request STF 11.5(c):

> "In 2005, PEP had a similar structure as 2004 with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Gas financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in the response to STF 11.5 b, the 2005 primary financial goal was not met."

Q. Even though the primary financial goal under the PEP was not met in 2005, were incentive bonuses paid?

A. Yes, they were. As explained in UNS Gas' supplemental response to STF 11.5(b):

> "... the financial performance goal, which was a trigger under the PEP program for UNS Electric, UNS Gas and Tucson Electric Power Company ("TEP"), was not met. The financial performance goal was not met, in part, because of unplanned outages at the coal generating units which required TEP to purchase power on the open market. In discussions with the Board of Directors, the desire was to recognize employee achievements distinct from financial measures. The Board deemed it appropriate to implement a Special Recognition Award to employees for achievements in 2005. Normally, PEP is paid at 50% to 150% of target; the Special Recognition Aware was paid at approximately 42% of the target for each of the operating companies."

Q. Are you aware of any recent Commission decisions that reached similar conclusions regarding the appropriate ratemaking treatment of incentive compensation and SERP expense?

A. Yes. As an illustrative example, in Decision No. 68487, February 23, 2006, in a Southwest Gas Corporation rate case, the Commission adopted Staff's recommendation for an equal sharing of costs associated with that utility's management incentive plan compensation expense, and adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Order 68487 that:

> "Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers."

The adjustments to expense for the SERP and for each of UNS Gas' incentive compensation programs are shown on Schedule C-6. The adjustment reduces O&M expense by $262,223. A related impact on payroll tax expense reduces that by $5,202.

<u>C-7, Emergency Bill Assistance Expense</u>

Q. Please explain Staff Adjustment C-7.

A. This adjustment increases test year expense to be included in the base rate revenue requirement determination by $21,600 to provide for an increase requested by the Company for emergency bill assistance. UNS Gas had included this $21,600 in its request for increased funding for its low-income weatherization program. UNS Gas also requested that the low-income weatherization program be included in the Commission-approved Demand Side Management (DSM) programs. Staff agrees with increasing the Company's requested allowance for emergency bill assistance by the $21,600, but disagrees that this should be part of a DSM program or that this particular expense should be included in the separate DSM surcharge rate. Accordingly, Staff has reflected the $21,600 increase in emergency bill assistance as an increase to operating expenses, so this can be included in base rates, and has excluded this expense from DSM programs. As shown on Schedule C-7, this adjustment increases operating expense by $21,600. The testimony of Staff witness Julie McNeely-Kirwan contains further explanations of Staff's reasons for this treatment.

<u>C-8, Remove Nonrecurring Severance Payment Expense</u>

Q. Please explain Staff Adjustment C-8.

A. This adjustment removes a nonrecurring severance payment of $52,388 recorded in test year expense. An email dated January 11, 2005 in UNS Gas' workpapers explain this item as follows: "There is an employee at UNS Gas who was let go in July 2004 who had worked in cost center 581 in Flagstaff. As part of his severance agreement, it was agreed not to pay him his final severance until January 2005. The gross amount of the check being issued is $52,287.56. The check in January will be charged to task G510857." The Company's payroll adjustment recognized that this severance payment was nonrecurring, and did not apply a pro forma payroll increase to it. However, the Company also did not remove it from test year expense. It relates to a an employee whose severance occurred in 2004, is nonrecurring, and should be removed from test year expense as shown in Staff Adjustment C-8.

C-9, Overtime Payroll Expense

Q. Please explain Staff Adjustment C-9.

A. This adjustment reduces the amount of pro forma expense in the Company's payroll adjustment. In that adjustment, the Company attempted to normalize test year overtime based on a two-year average. As shown on Schedule C-9, Staff has recalculated the overtime normalization adjustment two ways, and each results in a pro reduction UNS Gas' proposed overtime expense, in contrast with the Company's calculation which resulted in an increase. Schedule C-9, page 1, shows Staff's calculation of normalized overtime expense which results in a reduction of $123,010 to the UNS Gas' proposed amount. Schedule C-9, page 2, shows an alternative calculation, which reduces UNS Gas' proposed amount by $138,876.

Q. Are there aspects to the Company's calculated overtime adjustment with which Staff agrees?

A. Yes. Staff agrees with the concept of using a two-year average of 2004 and 2005 overtime cost to produce a normalized overtime expense adjustment. As shown on Schedule C-9, pages 1 and 2, the amount of overtime charged to Operating and Maintenance (O&M) expense, and the total amount of overtime cost in 2005 was considerably higher than in 2004. The UNS Gas recorded amount of overtime charged to O&M expense, and the total amount of overtime cost in the 2005 test year is higher than the average for the two-year period 2004-2005.

Q. Please explain the calculations shown on Schedule C-9.

A. Schedule C-9, page 1, focuses on the overtime charged to O&M expense. UNS Gas' pro forma adjustment reflects an increase to O&M expense for overtime of $1.070 million. This is shown on line 1 of Schedule C-9. As shown on lines 4-6, overtime charged to O&M expense totaled $781,386 in 2004 and approximately $1 million in 2005. The average for the two-years was $890,915. The UNS Gas pro forma adjustment for regular payroll charged to O&M expense reflected an increase of approximately 6.3%, as shown on lines 7-9. Applying this same increase to the two-year average overtime expense amount of $890,915 produces an annualized adjusted overtime O&M expense of $947,123, as shown on lines 11-12. The difference between the $947,123 in Staff's calculation and the $1.070 million in UNS Gas' calculation is a reduction to the UNS Gas-proposed overtime expense of approximately $123,000.

Schedule C-9, page 2, focuses on the total increase to overtime cost, including pro forma overtime amounts charged to O&M expense and to non-O&M accounts. UNS Gas' pro forma adjustment reflects a total overtime cost of approximately $1.403 million. This is shown on line 1 of Schedule C-9, page 2. As shown on lines 6-9, overtime charged to O&M and non-O&M accounts totaled $992,499 in 2004 and approximately $1.3 million in 2005. The average for the two-years was $1.148 million. The UNS Gas pro forma adjustment for regular payroll reflected an increase of approximately 6.3%, as shown on lines 10-12. Applying this same increase to the two-year average total overtime cost of $1.148 million produces an annualized adjusted total overtime cost of $1.221 million, as shown on lines 13-15. As shown on lines 1-3, the difference between the $1.403 million in UNS Gas' calculation and the $1.221 million in Staff's calculation is a reduction total pro forma overtime cost of approximately $182,000. The portion of total overtime charged to O&M expenses is 76.3 percent, as shown on lines 16-18. The corresponding adjustment to O&M expense is $138,876, as shown on line 5.

Q. Which amount of overtime expense adjustment did you reflect in Staff's determination of net operating income?

A. I used the lower of the two adjustment amounts. The $123,010 reduction to the Company's proposed overtime expense was carried forward to Schedule C.1, page 2, in the column for Staff Adjustment C-9.

<u>C-10, Payroll Tax Expense</u>

Q. Please explain Staff Adjustment C-10.

A. This adjustment reduces test year payroll tax expense for the impact of Staff's other adjustments to payroll. As shown on Schedule C-10, pro forma payroll tax expense is reduced by $13,356.

<u>C-11, Nonrecurring FERC Rate Case Legal Expense</u>

Q. Please explain Staff Adjustment C-11.

A. During the 2005 test year, UNS Gas incurred substantial legal expenses related to settlement discussions in an El Paso Natural Gas rate case at the Federal Energy Regulatory Commission (FERC). That case has been settled. The expenses related to settlement negotiations in that case during May through December 2005 expensed by UNS Gas in the test year are therefore nonrecurring and should be removed. Those amounts were identified by the Company in response to data request STF 5.91 and amount to $311,051.

C-12, Property Tax Expense

Q. Please explain Staff Adjustment C-12.

A. This adjustment reflects the known statutory assessment ratio of 24 percent applicable for 2007. The Arizona State Legislature passed House Bill No. 2779 which set a new rate schedule for property tax assessments. The new assessment rate schedule provides for decreasing the 25 percent rate applicable in 2005 in 0.5 percent steps each year until a 20 percent rate is attained in 2015. The Company's calculation used a 24.5 percent assessment rate and thus fails to recognize the impact of this known tax change prospectively.

Q. How did Staff determine its recommended assessment rate?

A. The current assessment rate in 2007 is 24 percent. Staff concluded that since the Commission approved rates are expected to become effective in mid-2007, and the Company's anticipated rate case interval is three years, as evidenced by the Company's proposed normalization period for rate case expense, the property tax rate that will be in effect for 2007 of 24 percent is appropriate.

In terms of determining the recommended assessment rate, I also considered how Staff's recommendation in the current UNS Gas rate case compares with Staff's similar determination in the recent Southwest Gas rate case. This comparison is summarized in the following table:

Utility:	UNS Gas, Inc.	Southwest Gas Corp.
Docket:	G-04204A-06-0463	G-01551A-04-0876
Test Year Ended:	December 31, 2005	August 31, 2004
New Rates Effective:	mid-2007	Order issued 2/23/06
Estimated Filing Interval:	3 years	3 to 4 years
Assessment Rate Used:	24 percent	24.5 percent
Corresponding Effective Year:	2007	2006

In the Southwest Gas case, it appears that the utility, Staff and RUCO all ultimately agreed on the appropriateness of using a 24.5 percent assessment rate effective for 2006 in conjunction with the test year in that case ending August 31, 2004. I believe the appropriateness of using the known 24 percent assessment rate in the current UNS Gas rate case is supported by the comparison in the above table.

Q. What is Staff's recommended property tax expense adjustment?

A. As shown on Schedule C-12, Staff's recommended adjustment reduces UNS Gas' proposed property tax expense by $80,290.

<u>**C-13, Worker's Compensation Expense**</u>

Q. Please explain Staff Adjustment C-13.

A. This adjustment reverses a UNS Gas' proposed adjustment to increase test year expense for using a cash basis, rather than an accrual accounting basis, for recognizing worker's compensation expenses for ratemaking purposes.

Q. How does the Company propose to treat worker's compensation expense for ratemaking purposes?

A. The Company proposes to increase test year recorded expenses by adjusting from the accrual basis that it uses for book accounting purposes to a cash basis for ratemaking.

Q. What is the basis for this Company proposal?

A. The Company apparently believes that a prior Commission ratemaking decision concerning Other Postemployment Benefits (OPEB) requires a similar treatment for worker's compensation expense. OPEBs cover post-retirement benefits, such as Company-paid retiree health care and life insurance. OPEBs are accounted for on an accrual basis, pursuant to FAS 106, for book purposes, but the Commission adjusted these to a pay-as-you-go method for ratemaking purposes in Decision No. 58664 (6/16/94) in a rate case involving Citizens Utilities Company, Arizona Gas Division. It is unclear from the information provided by UNS Gas how OPEB expenses have been treated for ratemaking purposes in subsequent cases.

Q. How was Worker's Compensation expense recorded on UNS Gas' books during the 2005 test year?

A. As explained in the Company's response to data request RUCO 6.09:

> "The Worker's Compensation expense is recorded under Statement of Financial Accounting Standards No. 112, Employer's Accounting for Postemployment Benefits ("FAS 112"). FAS 112 specifically states that post employment benefits are all types of benefits provided to former or inactive employees and worker's compensation is included as a post employment benefit."

Q. When was FAS 112 issued?

A. FAS 112 was issued by the Financial Accounting Standards Board ("FASB") in November 1992.

Q. When did FAS 112 first become required accounting?

A. FAS 112 was effective for fiscal years beginning after December 15, 1993. Basically, it has been part of required GAAP since 1994.

Q. Has UNS Gas proven that FAS 112 was not used for accounting or ratemaking purposes in Arizona since 1994?

A. No. The information provided by UNS Gas has not documented any Commission rulings requiring worker's compensation expense to be recorded on a cash basis for ratemaking purposes. Data request RUCO 6.06, for example, referenced UNS Gas' pro forma adjustment for worker's compensation expense and asked the Company to: "Please provide additional back-up information, which verifies the Commission's historical treatment of this expense is required to be recorded on a cash basis." The Company responded that: "UNS Gas does not have this additional back-up information."

Q. How does Staff propose to treat worker's compensation expense in the current case?

A. Staff proposes to treat the expense in accordance with the accrual accounting prescribed in FAS 112. There is no compelling reason to deviate from the generally accepted accounting for worker's compensation in the current UNS Gas rate case. The Company's proposed increase to worker's compensation expense of $34,234 is unjustified and should be rejected.

<u>C-14, Membership and Industry Association Dues</u>

Q. Please explain Staff's proposed adjustment for Membership and Industry Association Dues.

A. This adjustment reduces test year expense by $26,868, as shown on Schedule C-14. It removes 40 percent of UNS Gas' 2005 American Gas Association ("AGA") dues for

2005, which were $41,854. It also removes other discretionary membership and industry association dues which are not needed for the safe and reliable provision of gas utility service.

Q. Did UNS Gas' AGA dues increase substantially in 2005?

A. Yes. An Invoice provided by the Company in response to data request STF 16.1 indicated that 2004 AGA dues were $20,927 and 2005 dues were $41,854. The invoice indicates that the 2004 amount represents one-half of full dues and the 2005 amount represents the phase-in to full dues.

Q. How did you determine the 40 percent disallowance for AGA dues?

A. This was based upon a review of information in the two most recent National Association of Utility Regulatory Commissioners (NARUC) sponsored Audit Reports of the Expenditures of the American Gas Association. Copies of relevant pages from those audit reports are provided in Attachment RCS-3.

Q. What is the purpose of the NARUC-sponsored audits of AGA expenditures?

A. The purpose of the NARUC-sponsored audits of AGA expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. As stated in the June 2001 memo to the Chairs and Chief Accountants of the State Regulatory Commissions included with the NARUC-sponsored audit of 1999 AGA expenditures[9]: "Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities." The

[9] This is the most recent NARUC-sponsored audit report on AGA expenditures currently available.

NARUC-sponsored audit categorizes the AGA expenditures and, as stated in the aforementioned memo, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit."

Q. Have other regulatory commission required similar adjustments to utility-incurred AGA dues, based on the results of the NARUC-sponsored audits?

A. Yes. As an example, I have included in Attachment RCS-4, an excerpt from a Florida Public Service Commission Staff Memorandum (dated 12/23/03) in a City Gas Company rate case addressing this issue. As stated in that document:

"In City Gas's last rate case, In re: Request for rate increase by City Gas Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. In re: Application for a rate increase by City Gas Company of Florida, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake

Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment."

Q. What amount of membership dues expense has Staff removed from test year expense?

A. As shown on Schedule C-14, Staff has removed $26,868 in test year expense for membership dues.

<u>C-15, Fleet Fuel Expense</u>

Q. Please explain Staff Adjustment C-15.

A. This adjustment reduces the Company's proposed post-test year increase for vehicle fleet fuel expense. Staff's adjustment follows a similar format to the UNS Gas proposed adjustment for fleet fuel expense. Staff's adjustment allows for a pro forma fuel expense increase of $21,287 based on a cost of gasoline of $2.26 per gallon from a 3 Month Average Retail Price Chart as of January 17, 2007, at ArizonaGasPrices.com. UNS Gas' proposed adjustment is reduced by $52,439, as shown on Schedule C-15.

<u>C-16, Postage Expense</u>

Q. What adjustment has UNS Gas proposed for postage expense?

A. UNS Gas has proposed an adjustment to increase postage expense by $142,707. This is shown on in UNS Gas' filing, at Schedule C-2, page 4, line 5.

Q. Does Staff agree with that adjustment?

A. Not fully. Staff is in agreement that a postage increase has occurred and should be recognized for ratemaking purposes. To derive the annualized postage expense, Staff increased the test year recorded postage expense of $386,673 for the postage increase that became effective January 8, 2006 ($0.02 / $0.37) and for the increase in the number of customers from the test year average to year-end. As shown on Schedule C-16, Staff has calculated an adjustment for annualized postage expense of $414,285. This reduces UNS Gas' proposed amount of $529,380 by $115,095.

C-17, Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-17. This adjustment increases income tax expense by the amount shown on Schedule C-17 and decreases the Company' achieved operating income by a similar amount.

V. DEPRECIATION RATES

Q. Please discuss the new depreciation rates that UNS Gas has proposed.

A. The development of new depreciation rates is addressed in the testimony of UNS Gas witness Ronald White, who sponsors the Company's 2006 depreciation rate study. The table presented at page 10 of Dr. White's testimony summarizes the overall changes. The depreciation rates proposed by primary account are equivalent to a composite rate of 2.73 percent. This is a reduction of 0.21 percentage points in comparison to the current composite rate of 2.94 percent. On December 31, 2005 plant investment, the difference between the current and proposed new depreciation rates produces a decrease in annualized depreciation expense for the gas utility of $610,980. This is shown on Statement B, at numbered page 18 of Dr. White's Attachment REW-2.

Q. Please briefly describe the information you reviewed concerning UNS Gas' proposed depreciation rates.

A. The information I reviewed included the Commission's rules regarding depreciation, testimony and exhibits from the prior rate case, UNS Gas' application and testimony in the current case, UNS Gas' responses to data requests of Staff and other parties, Excel files supporting UNS Gas witness Ronald White's derivation of UNS Gas' depreciation rates, information provided to me by Staff, and other publicly available information.

Q. What Commission rules address the treatment of depreciation?

A. The Commission's rules at R14-02-102 address the treatment of depreciation. A copy of these rules are presented, for ease of reference, in Attachment RCS-6. The current version of the rules appear to have been adopted effective April 9, 1992. This pre-dates the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" which has resulted in revisions for financial reporting purposes, among other things, of the presentation of cost of removal information. I discuss SFAS No. 143 in more detail subsequently in my testimony.

Q. Did UNS Gas file a new depreciation study in the current rate case?

A. Yes. Exhibit REW-2 attached to Dr. White's testimony is the 2006 Depreciation Rate Study for UNS Gas, Inc.

Q. Please discuss the Company's proposed depreciation rates and how they were derived.

A. The new depreciation rates proposed by UNS Gas are summarized in Company witness Dr. White's testimony and are shown in detail in his exhibits, his Attachment REW-2.

The Company's proposed rates were developed using a depreciation system composed of the straight-line method, broad group procedure and remaining life technique.

Q. What impact do the new depreciation rates proposed by UNS Gas have?

A. As summarized on page 10 of Dr. White's testimony, based on December 31, 2005 plant investment, the new depreciation rates proposed by UNS Gas decrease depreciation expense by $610,980 (from $8,542,838 at present rates to $7,931,868 at the Company's proposed rates).

On a composite basis[10], the Company's proposed new rates produce an decrease of 0.21 percentage points, from the current composite rate of 2.94% to a composite at new rates of 2.73%.

Q. Before discussing specific issues associated with UNS Gas' proposed depreciation rates, could you please provide your understanding of some basic depreciation terminology?

A. Yes, of course.

Q. What is depreciation?

A. The Commission's rules at R14-2-102(A)(3) define "depreciation" as "an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life."

Q. What is net salvage?

A. The Commission's rules at R14-2-102(A)(5) define "net salvage" as "the salvage value of property less the cost of removal."

[10] UNS Gas does not apply its depreciation rates on a composite basis; this information is for comparative purposes only.

Q. What is "salvage value"?

A. The Commission's rules at R14-2-102(A)(5) define "salvage value" as:

> "the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; of if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts."

Q. What is the "cost of removal"?

A. The Commission's rules at R14-2-102(A)(5) define the "cost of removal" as "the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto."

Q. What is depreciation expense?

A. Depreciation expense is a charge to operating expense to reflect the recovery of depreciable utility plant. Depreciation rates are applied to a utility's depreciable utility plant to determine the amount of depreciation expense. Public utility depreciation expense is typically straight-line over the service life which results in an equal share of the cost of assets being assigned or allocated to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant and equipment is in service. [11]

Q. What is depreciable utility plant?

A. Public utilities record their plant investment activity in the individual plant accounts set-forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Plant additions, retirements and balances are maintained by plant

[11] National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices, August, 1996. ("NARUC Depreciation Manual"), p. 321. Also, Commission Rule R14-2-102, which defines "service life" as "the period between the date an asset is first devoted to public service and the date of its retirement from service."

account. An annual addition is the original cost of plant added to the account during the year. A retirement is recorded in the plant account by removing the original cost of a prior addition when such plant is removed from service. The plant balance is what is left at the end of an accounting period after accounting for additions and retirements.

Q. How is the annual depreciation expense calculated?

A. Annual depreciation expense, called an accrual, is calculated by applying a depreciation rate to plant balances.

Q. Is the depreciation accrual a cash expense?

A. No. Depreciation is considered a <u>non-cash</u> expense.

Q. Please explain the distinction between a cash and non-cash expense.

A. Depreciation expense is considered a non-cash accrual. This contrasts with payroll expense, for example, which involves the current outlay of cash. Depreciation expense does not involve a specific payment during the test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and is simultaneously recorded on the balance sheet in the accumulated depreciation account; which is shown as an offset to plant in service. The following accounting entries illustrate the difference:

Account	Description	Amount Dr. (Cr.)
403	Depreciation Expense	$ 1,000
108	Accumulated Depreciation	$ (1,000)
	To record depreciation	

various	Payroll Expense	$ 1,000
131	Cash	$ (1,000)
	To record payroll expense	

Q. What is the Accumulated Depreciation account?

A. Accumulated Depreciation, Account 108 in the USOA, is a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. From a regulatory perspective, Accumulated Depreciation can be considered a measure of the depreciation recovered from ratepayers. Commission Rule R14-2-102 defines "accumulated depreciation" as "the sum of the annual provision for depreciation from the time that the asset is first devoted to public service."

Q. How does depreciation expense impact a utility's revenue requirement?

A. Annual depreciation expense is a cost that is included in a public utility's revenue requirement. Because public utilities tend to be capital intensive, depreciation expense can be a significant component of the utility's revenue requirement.

Q. What is the objective of depreciation expense?

A. From a regulatory perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances. Additionally, many state regulatory commissions, including the ACC, have allowed utilities to recover through the commission-authorized depreciation rates, the utility's estimated future cost of removal, which is part of the net salvage component of the depreciation rates.

Q. Please illustrate how depreciation rates are developed.

A. The following calculation shows a straight-line whole-life depreciation rate assuming a 10-year average service life and a $1 million plant investment, and the whole life method. Each year the 10% depreciation rate would be applied to plant in service to produce an annual depreciation expense and an entry to accumulated depreciation:

Straight-Line Whole-Life Depreciation Rate Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: 100% / 10 Years = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
1	$ 100,000	$ (100,000)
2	$ 100,000	$ (200,000)
3	$ 100,000	$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 1,000,000	

Q. What happens at the end of an asset's life under this scenario?

A All things equal, at the end of 10 years, the plant balance will be 100% (or $1 million), and the accumulated depreciation balance will also be 100% (also $1 million). This equality is important to understanding issues relating to the cost of removal/negative net salvage.

Q. What is negative net salvage?

A. Negative net salvage is the difference between any salvage value and the cost of removal of the asset after completion of its service life. If the cost of removal exceeds the salvage amount, this produces negative net salvage. In this testimony I will use the terms negative net salvage and net cost of removal interchangeably. The ratemaking treatment of negative net salvage was raised by a Staff witness (Mr. Majoros) as a major issue affecting utility depreciation rates in a previous APS rate case, Docket No. E-01345A-03-0437. Negative net salvage can have a significant impact on a utility's depreciation rates and revenue requirement.

Q. What happens if estimated future negative net salvage is included in the calculation?

A. Assume a negative 55 percent (-55%) net salvage ratio. The above whole-life example with a 55% value for negative net salvage is as follows:

Straight-Line Whole-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [100% - (-55%)] / 10 Years = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
1	$ 100,000	$ (100,000)	$ 55,000	$ (55,000)
2	$ 100,000	$ (200,000)	$ 55,000	$ (110,000)
3	$ 100,000	$ (300,000)	$ 55,000	$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 1,000,000		$ 550,000	

In this example, negative net salvage increases the resulting whole-life depreciation rate from 10% to 15.5%, i.e., by 55%. This increase results from the inclusion of estimated future net cost of removal, including estimated future inflation.

Q. Please explain the "FAS 143 Regulatory Liability" column in the above example.

A. Because the Company has no current legal obligation to pay the estimated future inflated cost of removal (negative net salvage) amounts (i.e., has no asset retirement obligation), the excess amounts recovered through depreciation rates are accumulated in a regulatory liability account for financial reporting purposes, pursuant to Statement of Financial Accounting Standards No. 143. (SFAS 143) I will explain certain provisions in SFAS 143 that require such treatment in more detail later in my testimony.

Q. Why does negative net salvage increase the depreciation rate?

A. It increases the depreciation rate because negative salvage is, in effect, added to the original cost of the plant. Instead of 100% (which represents the original cost of assets), the numerator becomes 155%. This is equivalent to capitalizing or adding the estimated cost of removal to the original cost of the asset. In the above example, instead of recovering the original plant cost of $1 million, the depreciation rates would recover $1.55 million.

Q. What happens at the end of life under this scenario?

A. The plant balance will be 100% but the sum of the accumulated depreciation balance and the regulatory liability account will be 155%. Consequently, unlike the "zero net salvage scenario" shown above, when negative net salvage is included in a depreciation rate, there will not be an equality of plant and reserve at the end of an asset's life because the Company will have charged more depreciation than it paid for the original cost of the asset. Under these circumstances, equality will only be achieved if the Company actually spends additional money at the end of the asset's life.

Q. Is the Company required to pre-collect from ratepayers estimated future amounts of money that it might spend at the end of plant useful life?

A. Where there is no legal requirement to incur cost of removal, UNS Gas has no current legal liability to spend money for estimated future cost of removal, the Commission rules at R14-2-102(B)(3) require that: "The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systematic manner over the estimated service life of the plant." As discussed above, the Commission's rules define "net salvage" to include the cost of removal. Consequently, I conclude that the Commission's rules require cost of removal to be included in the utility's depreciation rates.

Q. If the Company does incur an obligation at the end of an asset's service life that requires spending money for removal, can the Company take the money out of accumulated depreciation?

A. No. Accumulated Depreciation is an unfunded account. Even though the Company collected money from ratepayers for future removal cost that had been included in past depreciation rates, it will have already spent that money on whatever it chose in the past: salaries, dividends, etc.

Q Please explain the concept of remaining life depreciation.

A. The remaining life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining life rather that the whole life of the asset.

Q. What happens when accumulated depreciation is incorporated into the numerator of the basic depreciation calculation?

A. If the 10-year asset is 3 years old, its remaining life would be 7 years (10 – 3 = 7). The accumulated depreciation account would be 30% of the original cost because the 10% depreciation rate would have been applied for three years (3 x 10% = 30%). The remaining life depreciation rate would then be 10%, calculated as follows:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: [100% - 30%] / [10 - 3 Years] = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
3		$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 700,000	

Under the example with the assumed 55% negative net salvage, and a 7-year remaining life, the results would be a 15.5% depreciation rate, as shown below:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [(100% - (-55%)) - (3 x 15.5%)] / [10 - 3 Years] = 15.5% Per Year
Depreciation Rate: [(108.5%)] / [7 Years] = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
3		$ (300,000)		$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 700,000		$ 385,000	

Q. Why would the whole-life depreciation rate in the example with negative net salvage and the remaining life depreciation rate in the negative net salvage example both be 15.5 percent?

A. In these examples, the remaining life depreciation rate and the whole-life depreciation rates are the same (15.5 percent) because I have assumed that the accumulated depreciation account is in balance. In other words, based on a continuation of the fundamental parameters, i.e., the 10-year service life and the negative 55% net salvage ratio, exactly the right amount of depreciation has been charged and collected in the past.

Q. What would happen if either of these fundamental parameters were to change?

A. If either the service life or net salvage parameter changes during the life of the plant, the accumulated depreciation account will be out of balance, and the remaining life rate will be either higher or lower than the whole-life rate depending on the direction of the imbalance. That is because the Company will have collected either too much depreciation or not enough depreciation in the past, given the current estimates of lives or future net salvage. The difference between the actual amount recovered, as included in the book depreciation reserve, and a theoretical estimate of what should be in the book reserve, is called a "reserve imbalance." The remaining life technique is often used to deal with such reserve imbalances.

Q. Since the last revision to the Commission's rules regarding the treatment of depreciation, has a significant accounting pronouncement been issued?

A. Yes. As noted above, it appears that the Commission's rules concerning the treatment of depreciation were last revised and became effective April 9, 1992. Since that date, generally accepted accounting principles (GAAP), specifically SFAS 143, highlight the amounts associated with estimated future cost of removal for which no current legal obligation exists and require that they be reported as Regulatory Liabilities for financial reporting purposes. A regulatory liability can be viewed as an amount owed to ratepayers.

Q. What is SFAS 143?

A. The Financial Accounting Standards Board ("FASB") is a standards-setting body for the public accounting profession. In June 2001, the FASB promulgated Statement of Financial Accounting Standards No. 143 (FAS 143). This pronouncement addresses the appropriate accounting for long-lived assets. It is effective for all fiscal years beginning after June 15, 2002. However, earlier application was encouraged. Pursuant to SFAS 143, all companies, both unregulated (e.g., Walmart) and regulated (e.g., UNS Gas) must review all of their long-lived assets to determine whether or not they have actual legal obligations to remove retired assets. For some plant and equipment, companies have a legal obligation to remove the asset at the end of the service life. These legal obligations for future removal are called asset retirement obligations ("AROs"). For other assets, no such obligation exists.

If a company does have an ARO, the fair value of the future retirement cost, which is determined using net present value techniques, is considered to be part of the original cost of the asset. That ARO is therefore capitalized (included in the original cost) and depreciated over the life of the asset. In essence, if a Company incurs a legal liability to spend money to remove an asset at the end of its life, that liability is part of the cost of the asset.

In contrast, if a company does not have such legal obligations, the future cost of removal will not be capitalized as part of the asset cost and will not be included in depreciation expense. Only the initial cost of the asset (which does not include estimated inflated future cost of removal for which no current liability exists), will be depreciated.

At the end of the asset's life, for assets without AROs, the accumulated depreciation account will equal the plant balance. In other words, under SFAS 143, there is symmetry between assets with and without AROs. In both cases, the accumulated depreciation will equal the original cost of the asset at the end of its life.

Q. How are AROs measured?

A. AROs are measured at their net present value, not their inflated future value.

Q. How are AROs recorded for accounting purposes?

A. As stated above, AROs are capitalized as a cost of the related asset and simultaneously recorded as a liability for those companies with a legal obligation to remove a retired asset. To illustrate, assuming an ARO of $500, the $500 would be debited (i.e., added) to plant and simultaneously credited (i.e., added) to the regulatory liability account. Each year, as the liability increases due to inflation, the increase is charged to accretion expense and credited to the liability, but the asset value remains the same. In other words, just as the original cost of the asset does not increase, neither does the capitalized asset retirement cost.

Q. What happens if a company does not have an asset retirement obligation pursuant to SFAS 143?

A. If a company does not have such obligations, the estimated future inflated cost of removal is not considered as a cost of the asset, and therefore it will not be included in the company's depreciation expense on its general purpose financial statements. SFAS 143, therefore, unbundles net salvage from depreciation rates. It does this in two ways: (1) by incorporating the net present value of an ARO in the cost of the asset, or (2) by excluding non-AROs from the depreciation rate calculations.

Q. What is the accounting impact of SFAS 143 for electric utilities?

A. Under Generally Accepted Accounting Principles ("GAAP"), electric utilities are required to review all of their assets to determine if they have any AROs. If a utility has any AROs, they are capitalized. Paragraph B73 of SFAS 143 provides an exception for regulated utilities, which allows them to continue to incorporate net salvage factors ("non-legal AROs") in depreciation rates even if they do not have AROs. Utilities are also required to determine the amount of any prior cost of removal collections relating to non- AROs that is now included in their accumulated depreciation accounts, and reclassify these and any such future charges as a regulatory liability in their financial statements. In other words, even with the paragraph B73 exception, SFAS 143 provides transparency through reporting disclosure requirements.

Q. What is the impact of SFAS 143 on electric regulatory accounting?

A. FERC addressed SFAS 143 in Docket RM02-7-000 which resulted in Order No. 631. FERC Order 631 essentially adopts SFAS 143 and integrates it into the Uniform System of Accounts. Utilities are required to review their long -lived assets to determine if they have any AROs. Where utilities do not have AROs, any charges for such amounts must be separately identified. FERC Order 631 defines cost of removal allowances for which there is no legal asset retirement obligation, as "non-legal retirement obligations." Past and future "non- legal AROs" must be specifically identified and accounted for separately in the depreciation studies, depreciation expense and the accumulated depreciation account. In Order 631, FERC maintains the transparency resulting from the "separation principle" for non-legal AROs that was established in paragraph B73 of SFAS 143. Paragraph 38 of Order 631 explains FERC's new requirements for non-legal AROs:

> "Instead, we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in Parts 101, 201 and account 31, Accrued depreciation - Carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals."

Q. Does FERC provide any additional insight as to the interpretation of these new rules?

A. Yes, at paragraph 39 of the order, FERC states:

"Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accumulated removal costs for other than legal retirement obligations recorded as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that the jurisdictional entities separately identify and quantify prospectively the amount of current accruals for specific allowances collected in rates for non-legal retirement obligations."

Q. Does FERC make any policy calls concerning the appropriate treatment of the disposition of prior and future collections contained in these separate allowances?

A. No. As indicated at paragraph 64 of the Order, FERC declined to make such calls on a policy basis. Rather, FERC will resolve the appropriate treatment of the dispositions of prior and future collections on a case-by-case basis.

Q. Does FERC's Order require anything new or more with respect to its requirement for detailed depreciation studies?

A. No. At paragraph 65 of the Order, FERC states that:

"... this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of

> detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost of removal, and salvage estimates in rates."

Additionally, footnote 45 states:

> "When an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate."

Thus, FERC recognizes distinctions between legal and non-legal AROs just as SFAS 143 recognizes those distinctions. On a going-forward basis, jurisdictional entities must be prepared to specifically identify and justify any non-legal AROs that they propose to include in rates.

Q. Has UNS Gas implemented SFAS 143?

A. Yes. The Company has implemented SFAS 143. Consistent with adopting this accounting principle for financial reporting purposes, UNS Gas reclassified prior year removal costs of approximately $3 million previously included in accumulated depreciation to the liability for asset retirements and removals in its Balance Sheets.

When initially adopting SFAS 143, companies such as UNS Gas, reclassified for financial statement reporting purposes their accumulated cost of removal for which there is no current legal obligation for removal, from Accumulated Depreciation and reported this as a Regulatory Liability.

As described in the notes to the consolidated financial statements of the UniSource Energy, TEP and Subsidiaries in their 2005 Securities and Exchange Commission ("SEC") Form 10-K, under the heading "Regulatory Assets and Liabilities":

> "... UNS Gas has recorded regulatory liabilities for the Net Cost of Removal for Interim Retirements from its distribution and general plant of $3 million as of December 31, 2005 and $2 million as of December 31, 2004."

Q. Are the "costs of removal" that were reclassified as a regulatory liability for financial reporting purposes the result of UNS Gas' past depreciation rates?

A. Essentially, yes. Similar to most utilities, UNS Gas' past depreciation rates have included negative net salvage. This has resulted in UNS Gas pre-collecting from ratepayers estimated future costs of removal for non-legal AROs, which under SFAS 143, have been reclassified for financial reporting purposes as a regulatory liability.

Plant and equipment are retired from service at the end of their useful lives. Sometimes the retired plant and equipment may be physically removed and can be resold for value. This is called gross salvage. The cost of removal net of the value received for the salvage constitutes net salvage. In more technical terms, gross salvage is the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property. Cost of removal is the cost incurred in connection with the retirement from service and the disposition of depreciable plant. As discussed above, net salvage is the difference between gross salvage and cost of removal.

Q. Are net salvage ratios included in the Company's depreciation rate calculations?

A. Yes. Substantial negative net salvage ratios are included in several of UNS Gas' depreciation rates. The inclusion of negative future net salvage ratios in UNS Gas' proposed depreciation rates result in depreciation rates that are significantly higher in many instances than if no cost of removal had been included. As noted above, the inclusion of net salvage in depreciation rates appears to be consistent with past practices of the utility and Commission, and appears to be required by Commission rule R14-2-102(B)(3).

Q. Do UNS Gas' proposed depreciation rates include estimated future removal costs?

A. Yes. As noted above, UNS Gas' proposed depreciation rates include estimated future removal costs, including estimated future inflation. UNS Gas has done this by including negative net salvage ratios in the development of depreciation rates for many, but not all, of its depreciable plant assets.

Q. Where does UNS Gas develop its estimated future cost of removal that are included in its proposed depreciation rates?

A. These are developed in Mr. White's Attachment REW-2, on Statement D (average net salvage), Statement E (present and proposed parameters) of those attachments.

Q. Did you request UNS Gas to provide its <u>actual</u> cost of removal and net salvage information by plant account?

A. Yes. This was requested in data request STF-5.28 for years 2000 through 2005.

Q. Did UNS Gas provide that requested information plant account?

A. UNS Gas provided some but not all of the requested information. In response to STF 5.28, the Company stated that: "The assets of UNS Gas were acquired from Citizens Communications Company ("Citizens") on August 11, 2003. Cost of removal and salvage data from periods prior to that date are not available." Data that UNS Gas did provide shows that there was no cost of removal in 2003 or 2004, cost of removal of totaling $3,535 for mains in 2005 and salvage (proceeds from the sale of transportation equipment) of $213,065 in 2005. In other words, in 2005, UNS Gas had net salvage of $209,530.

Q. Have you made a comparison of how much UNS Gas' proposed depreciation rates would collect annually for estimated future cost of removal with the Company's recent actual cost of removal?

A. No. During the course of my analysis, I started to make such a comparison, but concluded that it was not necessary for purposes of this case because the Commission's rules at R14-2-102 require net salvage to be included in the development of the utility's depreciation rates. Since I am not recommending an adjustment to reflect an alternative treatment of cost of removal in this case, the comparative calculation related to quantifying such an adjustment was not pursued as it would have been if an adjustment to the Company's approach was being recommended.

Q. Has UNS Gas' approach to including net salvage in depreciation rates been widely used in the utility industry?

A. Yes. Many regulated utilities have used this approach. It is even addressed in the NARUC's 1996 Public Utilities Depreciation Practices Manual as a recommended approach. On the other hand, the same NARUC Manual at page 157 also states:

> "Some commissions have abandoned the above procedure [gross salvage and cost of removal reflected in depreciation rates] and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred."

Q. In your opinion, is there a reasonable alternative to the approach used by UNS Gas?

A. Yes. Instead of incorporating estimated future cost of removal along with estimated future inflation into depreciation rates, providing a normalized level of removal cost as a current-period expense is a reasonable alternative for ratemaking purposes, in my opinion.

Q. Does the NARUC Manual indicate that some utility commissions are using this alternative approach?

A. Yes. The NARUC Manual at page 158 states that:

> It is frequently the case that net salvage for a class of property is negative, that is, cost of removal exceeds gross salvage. This circumstance has increasingly become dominant over the past 20 to 30 years; in some cases negative net salvage even exceeds the original cost of plant. Today few utility plant categories experience positive net salvage; this means that most depreciation rates must be designed to recover more than the original cost of plant. The predominance of this circumstance is another reason why some utility commissions have switched to current period accounting for gross salvage and, particularly, cost of removal.

Q. Could UNS Gas' approach result in accumulated depreciation exceeding the original cost of plant in service?

A. Yes. One of the mechanical problems with UNS Gas' approach is that it can result in a depreciation reserve actually exceeding the gross plant balance. That is because the depreciation rates proposed by UNS Gas for distribution plant include estimated future cost of removal, and therefore produce higher depreciation rates than are necessary to fully depreciate the original cost of the plant. Therefore, at the end of its life, the accumulated depreciation account exceeds the plant account balance. Referring back to the hypothetical illustration that I presented earlier, with a 55% negative net salvage assumption, at the end of the 10-year assumed useful life, the utility has recorded \$1.55 million in depreciation on a depreciable asset of \$1 million. During the plant's depreciable life, the utility had no asset retirement obligation, but it would have collected an extra \$550,000.

Q. How should the allowance for cost of removal be calculated?

A. Because the Commission's rules at R14-2-102 in their current form clearly require the inclusion of net salvage in the development of the utility's depreciation rates, and this is what UNS Gas has done, I am not in this proceeding recommending an alternative. Were it not for those rules, I believe there is substantial merit in the alternative recommended by the witness for Staff in the prior APS rate case cited above, which would provide for a normalized allowance for cost of removal based on the average of the most recent five years worth of actual net salvage activity. Essentially, the cost of removal is treated just as any other normalized operating expense.

Q. Are you aware of whether other regulatory commissions use that alternative approach for utility recovery of cost of removal?

A. Yes. A five-year average net salvage allowance approach has been used for many years by the Pennsylvania Public Utility Commission. In recent years, some other state regulatory commissions have used similar approaches that exclude estimated future cost of removal from the development of depreciation rates, and provide an allowance for the cost of removal based on an average of a utility's actual incurred cost.

Q. What are the advantages of that approach?

A. The five-year rolling average for recovery of cost of removal provides a reasonable method for addressing this controversial aspect of depreciation. UNS Gas' proposed development of depreciation rates essentially treats estimated future costs of removal (including estimated future inflation) as a current period expense, even when there is no current legal obligation to incur such cost. In contrast with UNS Gas' approach, a normalized expense allowance approach better conforms with the generally accepted accounting principles articulated in SFAS 143 by not treating estimated inflated future removal costs as if they were a current obligation and a current expense. Additional advantages offered by the normalized expense allowance approach include that it is simple, straight-forward and easy to implement, provides an opportunity for the Company to recover a normalized allowance for cost of removal based on recent actual cost, and avoids charging current customers for estimated future inflation. However, the Commission's rules at R14-2-102 in their present state would appear to preclude this alternative for purposes of this case.

Rule R14-2-102 is a rule of general applicability to electric utilities in the state of Arizona. Because I believe there is no compelling reason to treat cost of removal (where there is no current obligation to incur such cost) differently from other normalized operating expenses, I recommend that the Commission consider amending Rule R14-2-102 to allow treatment of cost of removal in the manner recommended by Staff's consultant in the prior APS rate case.

Q. Should the depreciation rates proposed by UNS Gas be adopted for use in this case?

A. Yes. The depreciation rates proposed by UNS Gas presented in Dr. White's Attachment REW-2 should be adopted for use in this case. The depreciation rates proposed by UNS Gas were developed in a manner that is consistent with the Commission's rules for depreciation rates. My review of the details provided in Dr. White's Attachment REW-2 and other information indicates that those new rates proposed by UNS Gas are consistent with industry accepted depreciation practices. As noted above in my testimony, the net change in percentage terms resulting from UNS Gas' proposed new depreciation rates in composite terms is fairly small, a decrease of 0.21 percentage points for UNS Gas plant.

Q. Do you have any other recommendations concerning the depreciation rates proposed by UNS Gas?

A. Yes. Each of the new depreciation rates proposed by UNS Gas should be clearly broken out between (1) a service life rate and (2) a net salvage rate. By doing this, the depreciation expense related to the inclusion of estimated future cost of removal in depreciation rates can be tracked and accounted for by plant account.

VI. CHANGES TO RULES AND REGULATIONS

Q. What revisions to rules and regulations has UNS Gas proposed that you are addressing?

A. I am addressing the revisions to the rules and regulations described in the direct testimony of UNS Gas witness Gary Smith at pages 19-20, specifically:

- Section 6.B.2.b, gas service line reimbursement.
- Section 10.C, billing terms.
- Section 10.j, electronic billing.
- Section 11.E, timing of terminations with notice
- Section 7, extension of lines

Q. What has UNS Gas proposed for the amount that the customer would reimburse the Company for the gas service line on the customer's property?

A. UNS Gas proposes to change Section 6.B.2.b such that the amount the customer would reimburse the Company for the gas service line on the customer's property was increased from $8.00 per foot to $16.00 per foot to reflect current costs. Other changes provide that the customer is now responsible for locating facilities on private property and removing landscaping prior to installation or is to be subject to applicable charges. For customers who provide the trench for the service line on their own property, the rate at which the customer will reimburse the Company has been increased to $12.00 per foot for the excess footage.

Q. Have you reviewed the cost support provided by UNS Gas in support of its proposed changes for service lines and establishments charges?

A. Yes. I have reviewed the information provided by UNS Gas in response to Staff set 13, including Staff data requests 13.2, 13.6 and 13.7. I conclude that reasonable cost support exists for the increased gas service line reimbursement rates proposed by UNS Gas. Increasing such reimbursement rates, as proposed by the Company, should also help alleviate the initial cost impacts associated with customer growth, by having the customer reimburse UNS Gas based on a reimbursement rate that is more closely aligned with the utility's cost. This should help alleviate a concern that the robust customer growth UNS Gas is experiencing may be a factor in driving up the cost of service to existing customers.

Q. Please discuss the changes UNS Gas is proposing for Section 7, Extension of Lines.

A. The Company has attached a redlined version of Section 7 (as well as the other sections of its proposed changes to rules and regulations) to Gary Smith's direct testimony in Exhibit GAS-2. Page 20 of his direct testimony states that these changes are to update the UNS Gas tariff to reflect current market conditions and make them consistent with the Company's policy of asking developers to pay a fair cost for infrastructure installed to serve their facilities. The changes to Section 7 proposed by UNS Gas are quite extensive and include, but are not limited to these:

- 7.A.1, has added: "If downstream usage changes or is altered by the Customer, the Customer may be responsible for costs to upgrade or enlarge the service line to accommodate additional capacity requirements."
- 7.B, changing the General Policy to read: "All service and main line extensions agreements are made on the basis of economic feasibility." A provision that the Company would extend thirty (30) feet of main for each applicant who connects a functioning water heater or furnace within four (4) months of the completion of the main is being deleted.
- 7.B.4.b has been changed to read: "If the [Incremental Contribution Study] ICS has an allowable investment that is more than the cost of the main extension, then the excess amount may be applied to reduce their cost of service line installation."

Previously, this provision had included a statement that: "All applicants will pay for the entire length of their service lines on their property," which is being deleted in UNS Gas' proposed changes.

- 7.B.4.f is being added, to provide as follows: "For the purposes of this rule, 'economic feasibility' means that the estimated incremental revenues derived from serving the Applicant, less the incremental gas cost to serve the Applicant, meets the estimated costs of serving the Applicant, including meeting capital costs as determined by the weighted average cost of capital authorized by the ACC in the Company's most recent general rate case. An extension will not be considered economically feasible if the Applicant does not install a functioning water heating and furnace within four (4) months of the completion of the main."

- 7.B.5, which addresses the method of refund is being substantially changed.

- 7.C.1.b, concerning Advances, is being changed to provide as follows: "The Company may require a subdivider, builder or developer to provide trenching for service lines and/or distribution mains and may also require the subdivider, builder or developer to provide bedding & shading material to Company specifications."

- 7.D.1, concerning Postponement of Advance, is reworded to provide in part as follows: "When advances are postponed, the Applicant may be required to furnish to the Company, a Company-approved surety, to assure payment of any postponed amounts throughout the term of the facilities extension agreement up until the end of the postponement period."

- 7.D.5, a revision proposed by UNS Gas removes the definition of "Branch Services" from that provision.

- 7.D.6.c, is added to provide that: "The estimated cost of main extension and any resulting Main Extension Agreement is valid for ninety (90) days from the date of

Company issue. Any signed agreement with appropriate payment where construction does not commence within ninety (90) days may be subject to review, recalculation and adjustment of advance requirements."

- 7.D.16, Taxes Associated with Nonrefundable Contributions and Advances, contains an extensive addition, which appears to substantially clarify these provisions.

Q. What is your assessment of the fairly extensive changes proposed by UNS Gas to Section 7 regarding Extension of Lines?

A. While one could quibble about whether some of the wording changes proposed by the Company are really an improvement over the existing provisions, overall the Company-proposed changes appear to be appropriate and consistent with a policy of asking developers to pay a fair cost for infrastructure installed to serve their facilities.

Q. Why is UNS Gas proposing to change the provisions of its tariff at Section 10.C, Billing Terms?

A. As explained in the Company's response to STF 13.8, the current terms in the Rules and Regulations section were approved by the Commission in Decision No. 66028 with the acquisition of the utility operation from Citizens. The revisions proposed by UNS Gas are intended to align the UNS Gas' "Billing Terms" with those of TEP and UNS Electric (both UniSource Energy Companies), thereby minimizing confusion among UNS Gas and UNS Electric customers who are often the same individuals. As explained further in the response to STF 13.9(c):

> "TEP's current due date and time periods for late penalty charges are the same as those proposed by UNS Gas. Proposed revisions to UNS Electric's Rules and

> Regulations were filed on December 15, 2006. The proposed UNS Electric revisions match those of UNS Gas and TEP."

Q. Does Staff agree with this proposal by UNS Gas?

A. Yes. Minimizing customer confusion by standardizing billing terms for the UniSource Energy Companies is an appropriate objective. The changes proposed by UNS Gas also appear to be consistent with the specifications of the Arizona Administration Cost ("AAC") at R14-2-310(c). Consequently, Staff agrees with the UNS Gas-proposed changes to Section 10.C. In order that these changes not present a hardship on UNS Gas customers, there should be a six month waiver in the late payment penalty charge. The Company has proposed to reduce the number of days, from 15 to 10, as the period a customer may avoid a late payment penalty. For the first 6 months, the penalty should be waived from day 10. After the initial 6 months, the Company should be able to charge the penalty after day 10. This temporary six-month transition period should help alleviate any hardship on customers from this change in billing terms.

Q. What is the basis for UNS Gas' proposed changes to Section 10.J, Electronic Billing?

A. As explained in the Company's response to STF 13.10(a):

> "UNS Gas' proposed provision for electronic billing was based on TEP's electronic billing program. The new electronic billing program will have the same capabilities once UNS Gas converts to its new customer information system. The Company did not make comparisons with other Arizona utilities concerning electronic billing."

Q. Have UNS Gas' utility affiliates already begun to offer e-bill programs?

A. Yes. As explained in the Company's response to STF 13.10(b):

> "TEP e-bill began in May of 2003. UNS Electric launched e-bill in January 2006. For both Companies, customers can sign up for e-bill via telephone or the company web site. Customer are notified via email that their bill is ready to view."

As indicated in the response to STF 13.10(c), the customer response to e-bill appears to be positive, with a growing number of TEP and UNS Electric customers signing up and using it.

Q. Does UNS Gas anticipate any savings (e.g., postage, bill printing, etc.) from electronic billing?

A. Yes. As indicated in the response to STF 13.10(d), the Company estimates that during the test year it realized savings in postage, bill stock, mailing envelopes and remittance envelopes of approximately $4,000.

Q. Does Staff support UNS Gas' proposal to offer its customers an e-bill option?

A. Yes.

Q. Please discuss UNS Gas' proposal to revise Section 11.E.

A. This proposal is presented in UNS Gas' witness Gary Smith's testimony at page 20. The Company proposes to shorten the advance notice provision from ten days to five days. As explained in the response to STF 13.11(d) and (g), the five days provision is based on AAC R14-2-311(E)(1), and TEP and UNS Electric currently match the AAC's five day advance notice provision. As explained in response to STAF 13.11(f) the current ten days and the UNS Gas-proposed five days are both stated in terms of calendar days. Information provided by the Company in response to STF 13.11(b) and (c) lists the number of Suspension of Gas Service Notices mailed to customers and the number of terminations UNS Gas conducted, respectively, for 2004 through 2006, and for August 11 through December 31, 2003. The 2004 through 2006 data is impacted by moratoriums on mailing notices and disconnects that were effective for portions of those years.

Q. Does Staff agree with UNS Gas' proposed revision to Section 11.E?

A. In general, Staff supports the standardization of tariff provisions for rules and regulations for the UniSource Energy Companies, including UNS Gas. Staff does not object to the UNS Gas' proposed revision to Section 11.E; however, Staff is concerned that the shortening of notice time could present a hardship to customers. Therefore, Staff recommends that during the first six months after the notification provisions are approved, the Company allow affected customers the current ten calendar days to respond to a termination of service notice before actually disconnecting the customers. After six months, the new terms in Section 11.E would be enforceable as stated.

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, PSC staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Washington, Washington, D.C., Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed was the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)

U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. - Partial and Immediate (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-7650	Consumers Power Company – Final (Michigan PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)
U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)

R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
R-860378	Duquesne Light Company Surrebuttal (Pennsylvania PUC)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)
R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)

R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)
Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)

PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)
E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)

Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016,	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
Phase I	
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)
97-12-020	
Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)

Attachment RCS-2
Staff Accounting Schedules
Accompanying the Direct Testimony of Ralph C. Smith

Schedule	Description	Pages
	Revenue Requirement Summary Schedules	
A	Calculation of Revenue Deficiency (Sufficiency)	1
A-1	Gross Revenue Conversion Factor	1
B	Adjusted Rate Base	1
B.1	Summary of Adjustments to Rate Base	1
C	Adjusted Net Operating Income	1
C.1	Summary of Net Operating Income Adjustments	3
D	Capital Structure and Cost Rates	1
	Rate Base Adjustments	
B-1	Remove Construction Work in Progress	1
B-2	Remove GIS Deferral	1
B-3	Cash Working Capital - Lead/Lag Study	1
B-4	Accumulated Deferred Income Taxes	1
	Net Operating Income Adjustments	
C-1	Revenue Annualization	1
C-2	Weather Normalization	1
C-3	Adjustment to Bad Debt Expense	1
C-4	Remove Depreciation & Property Taxes for CWIP	1
C-5	Remove Amortization of Deferred GIS Cost	1
C-6	Incentive Compensation and SERP	1
C-7	Emergency Bill Assistance Expense	1
C-8	Remove Nonrecurring Severance Payment Expense	1
C-9	Overtime Payroll Expense	2
C-10	Payroll Tax Expense	1
C-11	Nonrecurring FERC Rate Case Legal Expense	1
C-12	Property Tax Expense	1
C-13	Worker's Compensation Expense	1
C-14	Membership and Industry Association Dues	1
C-15	Fleet Fuel Expense	1
C-16	Postage Expense	1
C-17	Interest Synchronization	1
	Total Pages	31

UNS Gas Inc.
Computation of Increase in Gross Revenue Requirement

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule A
Page 1 of 1

Line No.	Description	Reference	UNS Proposed Original Cost (A)	UNS Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value (D)
1	Adjusted Rate Base	Sch. B	$ 161,661,361	$ 191,177,715	$ 154,541,358	$ 184,057,711
2	Rate of Return	Sch. D	8.80%	7.44%	8.12%	6.82%
3	Operating Income Required		$ 14,223,179	$ 14,223,179	$ 12,548,758	$ 12,548,758
4	Net Operating Income Available	Sch. C	$ 8,428,981	$ 8,428,981	$ 9,664,497	$ 9,664,497
5	Operating Income Excess/Deficiency		$ 5,794,198	$ 5,794,198	$ 2,884,261	$ 2,884,261
6	Gross Revenue Conversion Factor	Sch. A-1	1.6649	1.6649	1.636969	1.636969
7	Overall Revenue Requirement		$ 9,646,901	$ 9,646,901	$ 4,721,446	$ 4,721,446

Notes and Source

Cols. A & B: UNS Gas, Inc. filing, Schedule A-1

UNS Gas, Inc.
Computation of Gross Revenue Conversion Factor

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule A-1

Line No.	Description	Company Proposed (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00000%
2	Less: Uncollectible Revenue	0.51%	0.51052%
3	Taxable Income as a Percent	99.49%	99.48948%
4	Less: Federal and State Income Taxes	39.43%	38.40095%
5	Change in Net Operating Income	60.06%	61.08853%
6	Gross Revenue Conversion Factor	1.6649	1.636969

Notes and Source
Col.A: UNS Gas Inc. Filing, Schedule C-3
Col.B: Response to STF 5.76, item 6

Components of Revenue Requirement Increase

	Amount	Percent
Net Income	$ 2,884,262	61.09%
Federal and State Income Taxes	$ 1,813,080	38.40%
Uncollectibles	$ 24,104	0.51%
Total Revenue Increase	$ 4,721,446	100.00%

UNS Gas, Inc.
Original Cost and RCND Adjusted Rate Base

Test Year Ended December 31, 2005

Line No.	Description	Original Cost: As Adjusted by UNS (A)	Original Cost: Staff Adjustments (B)	Original Cost: As Adjusted by Staff (C)	RCND: As Adjusted by UNS (D)	RCND: Staff Adjustments (E)	RCND: As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 279,169,694	$ (7,189,231)	$ 271,980,463	$ 374,243,421	$ (7,189,231)	$ 367,054,190
2	Less: Accumulated Depreciation	$ (72,006,708)	$ -	$ (72,006,708)	$ (97,114,865)	$ -	$ (97,114,865)
3	Net Utility Plant in Service	$ 207,162,986	$ (7,189,231)	$ 199,973,755	$ 277,128,556	$ (7,189,231)	$ 269,939,325
4	Southern Union Acquisition Premium	$ -	$ -	$ -	$ -	$ -	$ -
5	Less: Accum. Amort. - So. Union Acq. Premium	$ -	$ -	$ -	$ -	$ -	$ -
6	Net Southern Union Acquisition Premium	$ -		$ -	$ -	$ -	$ -
7	Citizens Acquisition Discount	$ (30,709,738)	$ -	$ (30,709,738)	$ (41,822,562)	$ -	$ (41,822,562)
8	Less: Accum. Amort. - Citizens Acq. Discount	$ (1,876,981)	$ -	$ (1,876,981)	$ (2,560,308)	$ -	$ (2,560,308)
9	Net Citizens Acquisition Discount	$ (28,832,757)	$ -	$ (28,832,757)	$ (39,262,254)	$ -	$ (39,262,254)
10	Total Net Utility Plant	$ 178,330,229	$ (7,189,231)	$ 171,140,998	$ 237,866,302	$ (7,189,231)	$ 230,677,071
11	Customer Advances for Construction	$ (7,283,595)	$ -	$ (7,283,595)	$ (7,786,962)	$ -	$ (7,786,962)
							$ -
12	Customer Deposits	$ (3,040,484)	$ -	$ (3,040,484)	$ (3,040,484)	$ -	$ (3,040,484)
							$ -
13	Accumulated Deferred Income Taxes	$ (6,484,809)	$ 195,336	$ (6,289,473)	$ (6,484,809)	$ 195,336	$ (6,289,473)
14	Total Deductions	$ (16,808,888)	$ 195,336	$ (16,613,552)	$ (17,312,255)	$ 195,336	$ (17,116,919)
15	Allowance for Working Capital	$ (1,045,146)	$ 770,960	$ (274,186)	$ (1,045,146)	$ 770,960	$ (274,186)
							$ -
16	Regulatory Assets	$ 1,204,887	$ (897,068)	$ 307,819	$ 1,204,887	$ (897,068)	$ 307,819
							$ -
17	Regulatory Liabilities	$ (19,721)	$ -	$ (19,721)	$ (19,721)	$ -	$ (19,721)
18	Total Rate Base	$ 161,661,361	$ (7,120,003)	$ 154,541,358	$ 220,694,067	$ (7,120,003)	$ 213,574,064

Notes and Source
Cols. A and D: UNS Gas Inc. filing, Schedule B-1

Fair Value Calculation (Per Company)

Original Cost	$ 161,661,361	
RCND	$ 220,694,067	
Total	$ 382,355,428	
Average (Fair Value)	$ 191,177,715	See Sch. A

Fair Value Calculation (Per Staff)

Original Cost	$ 154,541,358	
RCND	$ 213,574,064	
Total	$ 368,115,422	
Average (Fair Value)	$ 184,057,711	See Sch. A

UNS Gas, Inc.
Summary of Rate Base Adjustments

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule B.1

Line No.	Description	Staff Adjustments	CWIP B-1	GIS Deferral B-2	Cash Working Capital B-3	ADIT B-4	B-5	B-6
1	Gross Utility Plant in Service	$ (7,189,231)	$ (7,189,231)					
2	Less: Accumulated Depreciation	$ -						
3	Net Utility Plant in Service	$ (7,189,231)	$ (7,189,231)	$ -	$ -	$ -	$ -	$ -
4	Southern Union Acquisition Premium	$ -						
5	Less: Accum. Amort. - So. Union Acq. Premium	$ -						
6	Net Southern Union Acquisition Premium	$ -						
7	Citizens Acquisition Discount	$ -						
8	Less: Accum. Amort. - Citizens Acq. Discount	$ -						
9	Net Citizens Acquisition Discount	$ -						
10	Total Net Utility Plant	$ (7,189,231)	$ (7,189,231)	$ -	$ -	$ -	$ -	$ -
11	Customer Advances for Construction	$ -						
12	Customer Deposits	$ -						
13	Accumulated Deferred Income Taxes	$ 195,336				$ 195,336		
14	Total Deductions	$ 195,336	$ -	$ -	$ -	$ 195,336	$ -	$ -
15	Allowance for Working Capital	$ 770,960			$ 770,960			
16	Regulatory Assets	$ (897,068)		$ (897,068)				
17	Regulatory Liabilities	$ -						
18	Total Rate Base	$ (7,120,003)	$ (7,189,231)	$ (897,068)	$ 770,960	$ 195,336	$ -	$ -

UNS Gas, Inc.
Adjusted Net Operating Income

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C

Line No.	Description	As Adjusted by UNS	Staff Adjustments	As Adjusted by Staff
		(A)	(B)	(C)
	Operating Revenues			
1	Gas Retail Revenues	$ 45,689,225	$ 104,395	$ 45,793,620
2	Other Operating Revenues	$ 1,480,303	$ -	$ 1,480,303
3	Total Operating Revenues	$ 47,169,528	$ 104,395	$ 47,273,923
	Operating Expenses			
4	Purchased Gas	$ 355,528	$ -	$ 355,528
5	Other O&M Expenses	$ 24,459,035	$ (954,445)	$ 23,504,590
6	Depreciation & Amortization	$ 7,220,392	$ (495,289)	$ 6,725,103
7	Taxes Other Than Income Taxes	$ 4,730,094	$ (265,732)	$ 4,464,363
8	Income Taxes	$ 1,975,498	$ 584,344	$ 2,559,842
9	Total Operating Expenses	$ 38,740,547	$ (1,131,121)	$ 37,609,426
10	Net Operating Income	$ 8,428,981	$ 1,235,516	$ 9,664,497

Notes and Source

Col. A: UNS Gas Inc. filing, Schedule C-1
Col. B: Staff Schedule C.1

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended December 31,2005

Line No.	Description	Stafff Adjustments	Revenue Annualization C-1	Weather Normalization C-2	Adjustment to Bad Debt Expense C-3	Remove Depreciation & Property Taxes for CWIP C-4	Remove Amortization of Deferred GIS Cost C-5
	Operating Revenues						
1	Gas Retail Revenues	$ 104,395	$ 102,433	$ 1,962			
2	Other Operating Revenues	$ -					
3	Total Operating Revenues	$ 104,395	$ 102,433	$ 1,962	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas	$ -					
5	Other O&M Expenses	$ (954,445)			$ 1,263		
6	Depreciation & Amortization	$ (495,289)				$ (196,266)	$ (299,023)
7	Taxes Other Than Income Taxes	$ (265,732)				$ (166,884)	
9	PRE-TAX OPERATING EXPENSES	$ (1,715,465)	$ -	$ -	$ 1,263	$ (363,150)	$ (299,023)
10	PRE-TAX OPERATING INCOME	$ 1,819,860	$ 102,433	$ 1,962	$ (1,263)	$ 363,150	$ 299,023
11	Income Taxes	$ 584,344	$ 39,537	$ 757	$ (487)	$ 140,169	$ 115,417
11	TOTAL OPERATING EXPENSES	$ (1,131,121)	$ 39,537	$ 757	$ 776	$ (222,981)	$ (183,606)
12	OPERATING INCOME	$ 1,235,516	$ 62,896	$ 1,205	$ (776)	$ 222,981	$ 183,606

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per Company response to STF 5.76, Part 6

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended December 31,2005

Line No.	Description	Incentive Compensation and SERP	Emergency Bill Assistance Expense	Remove Nonrecurring Severance Payment Expense	Overtime Payroll Expense	Payroll Tax Expense	Nonrecurring FERC Rate Case Legal Expense
		C-6	C-7	C-8	C-9	C-10	C-11
	Operating Revenues						
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas						
5	Other O&M Expenses	$ (262,223)	$ 21,600	$ (52,388)	$ (123,010)		$ (311,051)
6	Depreciation & Amortization						
7	Taxes Other Than Income Taxes	$ (5,202)				$ (13,356)	
9	PRE-TAX OPERATING EXPENSES	$ (267,425)	$ 21,600	$ (52,388)	$ (123,010)	$ (13,356)	$ (311,051)
10	PRE-TAX OPERATING INCOME	$ 267,425	$ (21,600)	$ 52,388	$ 123,010	$ 13,356	$ 311,051
11	Income Taxes	$ 103,221	$ (8,337)	$ 20,221	$ 47,479	$ 5,155	$ 120,059
11	TOTAL OPERATING EXPENSES	$ (164,204)	$ 13,263	$ (32,167)	$ (75,531)	$ (8,201)	$ (190,992)
12	OPERATING INCOME	$ 164,204	$ (13,263)	$ 32,167	$ 75,531	$ 8,201	$ 190,992

Notes and Source
Combined Effective Tax Rate* 38.598%
* Per Company response to STF 5.76, Part 6

UNS Gas, Inc.
Summary of Net Operating Income Adjustments

Test Year Ended December 31,2005

Line No.	Description	Property Tax Expense	Worker's Compensation Expense	Membership and Industry Association Dues	Fleet Fuel Expense	Postage Expense	Interest Synchronization
		C-12	C-13	C-14	C-15	C-16	C-17
	Operating Revenues						
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas						
5	Other O&M Expenses		$ (34,234)	$ (26,868)	$ (52,439)	$ (115,095)	
6	Depreciation & Amortization						
7	Taxes Other Than Income Taxes	$ (80,290)					
9	PRE-TAX OPERATING EXPENSES	$ (80,290)	$ (34,234)	$ (26,868)	$ (52,439)	$ (115,095)	$ -
10	PRE-TAX OPERATING INCOME	$ 80,290	$ 34,234	$ 26,868	$ 52,439	$ 115,095	$ -
11	Income Taxes	$ 30,990	$ 13,214	$ 10,370	$ 20,240	$ 44,424	$ (118,085)
11	TOTAL OPERATING EXPENSES	$ (49,300)	$ (21,020)	$ (16,498)	$ (32,199)	$ (70,671)	$ (118,085)
12	OPERATING INCOME	$ 49,300	$ 21,020	$ 16,498	$ 32,199	$ 70,671	$ 118,085

Notes and Source

Combined Effective Tax Rate* 38.598%

* Per Company response to STF 5.76, Part 6

UNS Gas, Inc.
Capital Structure & Cost Rates

Docket No. G-04204A-06-0463
Schedule D

Test Year Ended December 31, 2005

Line		Capitalization		Cost	Weighted Avg.
No.	Capital Source	Amount	Percent	Rate	Cost of Capital
	UNS - Proposed				
1	Short-Term Debt	n/a	n/a	n/a	n/a
2	Long-Term Debt	$ 98,859	50.00%	6.60%	3.30%
3	Common Stock Equity	$ 98,859	50.00%	11.00%	5.50%
4	Total Capital	$ 197,718	100.00%		8.80%
	ACC Staff - Proposed				
5	Short-Term Debt	n/a	n/a	n/a	n/a
6	Long-Term Debt	$ 98,859	55.33%	6.60%	3.65%
7	Common Stock Equity	$ 79,804	44.67%	10.00%	4.47%
8	Total Capital	$ 178,663	100.00%		8.12%
9	Difference				-0.68%
10	Weighted Cost of Debt				3.65%

Notes and Source

Lines 1-4: UNS Gas Inc. filing, Schedule D-1
Lines 5-8: Staff witness David Parcell

UNS Gas, Inc.
Remove Construction Work in Progress

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule B-1

Line No.	Description	Amount	Reference
1	Remove Construction Work in Progress	$ (7,189,231)	A&B

Notes and Source
A: UNS Gas Filing, Schedule B-2, page 2, line 1
B: Testimony of Staff witness Ralph Smith

UNS Gas, Inc.
Remove GIS Deferral

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	Remove GIS Deferral	$ (897,068)	A&B

Notes and Source

A: UNS Gas Filing, Schedule B-2, page 2, line 16
B: Testimony of Staff witness Ralph Smith

FERC Account 183

UNS Gas, Inc.
Cash Working Capital - Lead/Lag Study
For the Test Year Ending 12/31/05

Line No.	Description (A)	FERC	Per UNS Gas Pro Forma Test Year Amount (A)		Staff Adjustments (B)	Staff Adjusted (C)	Expense Lag Days (D)	Net Lag Days (RevLag - Col. D) (E)	Lead/Lag Factor (Col. E/365) (F)	Cash Working Capital Required (Col. F X Col.C) (G)
	Operating Expenses:									
	Non-Cash Expenses -									
1	Bad Debts Expense	904	$ 722,634	1a	1,263	723,897				$ -
2	Depreciation	403/404	7,950,183	1.4a	(196,266)	7,753,917				-
3	Amortization	406	(729,791)	1.4b	(299,023)	(1,028,814)				-
4	Deferred Income Taxes		3,178,719			3,178,719				-
	Other Operating Expenses -									
5	Salaries and Wages (UNSG Direct Employees)	Multi	7,287,745	2a	(175,398)	7,112,347	24.50	14.45	0.0396	281,649
6	Incentive Pay (UNSG Direct Employees)	Multi	257,895	3a	(63,430)	194,466	267.00	(228.05)	(0.6248)	(121,502)
7	Purchased Gas	Calc	78,101,248	4a	148,392	78,249,640	30.97	7.98	0.0219	1,714,759
8	Office Supplies and Expenses	921	1,365,974	1.2a	(5,640)	1,360,334	20.72	18.23	0.0499	67,881
9	Injuries and Damages	925	574,128	1.2b	(34,234)	539,894	64.75	(25.80)	(0.0707)	(38,171)
10	Pensions and Benefits	926	2,452,071	1.2c	-	2,452,071	54.66	(15.71)	(0.0430)	(105,439)
11	Support Services - TEP (Direct Labor, Burdens, System Alloc.)	Note A.	4,570,692	6a	(198,794)	4,371,899	44.91	(5.96)	(0.0163)	(71,262)
12	Property Taxes	408	4,103,376	1.4c	(247,174)	3,856,202	213.00	(174.05)	(0.4768)	(1,838,637)
13	Payroll Taxes	408	537,877	1.4d	(18,558)	519,320	19.30	19.65	0.0538	27,939
14	Current Income Taxes		(1,203,222)		2,397,424	1,194,202	41.42	(2.47)	(0.0068)	(8,121)
15	Interest on Customer Deposits	431	170,459	1.4e	-	170,459	182.50	(143.55)	(0.3933)	(67,042)
16	Other Operations and Maintenance	Multi	7,501,807	X.	(478,213)	7,023,594	53.10	(14.15)	(0.0388)	(272,515)
17	Total Operating Expenses		116,841,795		830,351	117,672,146				
	Other Cash Working Capital Elements:									
18	Interest on Long-Term Debt		5,334,825		305,935	5,640,760	91.62	(52.67)	(0.1443)	(813,962)
19	Revenue Taxes and Assessments	Calc	$ 18,788,535	L.	(6,405,918)	12,382,617	76.25	(37.30)	(0.1022)	(1,265,503)
20	Total Cash Working Capital - Calculated									$ (2,509,926)
21	Total Cash Working Capital - Per UNS Gas Filing, Schedule B-5, page 3 of 3									(3,280,886)
22	Adjustment to Cash Working Capital									770,960

Notes and Source
Col. A: UNS Gas filing, Schedule B-5, page 3 of 3
RUCO 1.10 2005 UNSG Lead-Lag Summary.xls
Revenue Lag, in days 38.95
Col.B: Staff workpapers for CWC calculation

	Per Company	
ProForma Operating Expenses - Excluding Income Taxes	$ 36,765,050	1.4f
Purchased Gas Lead/Lag Only	78,101,248	4a
ProForma Oper. Exp. To Tie Too - Excl Income Taxes	114,866,298	
Less: 1a, 1.4a, 1.4b, 2a, 3a, 4a, 1.2a, 1.2b, 1.2c, 6a, 1.4c, 1.4d, 1.4e	107,364,491	
Other O&M	$ 7,501,807	X.

Line 14, Col.C, Current income taxes:

Per UNS Gas	(1,203,222)	Col.A, line 14
Staff adjustments to net operating income statement	584,344	Schedule C
Income taxes for revenue increase	1,813,080	Schedule A-1
Total current income taxes for CWC calculation	1,194,202	

UNS Gas, Inc.
Accumulated Deferred Income Taxes

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount (A)	Reference
	Adjustment to ADIT:			
1	For GIS deferral that UNS Gas added to rate base that Staff has removed	283	$ 346,250	Note A
2	SERP	190	$ (86,506)	Note B
3	Incentive Comp related ADIT	190	$ (64,408)	Note B
4	Total adjustment to ADIT		$ 195,336	

Notes and Source

A UNS Gas workpaper "H1 - GPS Reg Asset"

B Staff has removed SERP from operating expenses and allocated incentive comp expense 50/50 to shareholders and ratepayers. This adjustment coordinates the corresponding ADIT amounts with those recommendations.

	Account and Description	Per Books (1)	UNS Gas Adjustment (2)	UNS Gas Adjusted	Staff Adjustment
	Account 190				
5	SERP	$ 88,747	$ (2,241)	$ 86,506 a	$ (86,506) B
6	Incentive Comp - PEP	$ 27,840		$ 27,840	$ (13,920) (3)
7	Long Term Incentive Comp	$ 100,975		$ 100,975	$ (50,488) (3)
8	Incentive Comp related ADIT	$ 128,815		$ 128,815	$ (64,408)

(1) Response to Staff DR 5.36
(2) UNS Gas, ADIT workpapers
(2a) UNS Gas workpaper "Pro Forma ADIT - Account 190" "SERP 12 D"
(3) Staff adjustment reflects a 50/50 allocation of incentive compensation responsibility between ratepayers and shareholders

UNS Gas, Inc.
Adjustment to Annualize Gas Retail Revenue

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	UNS Gas Adjustment to Annualize Gas Retail Revenue	$ 725,682	A
2	Staff Recommended Annualized Gas Retail Revenue	$ 828,115	B
3	Adjustment to Annualized Gas Retail Revenue	$ 102,433	L2 - L1

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 1, line 1

B: Total annualization adjustments calculated for the rate classes shown on Staff workpapers C-1.1, C-1.2 and C-1.3

FERC 480

UNS Gas, Inc.
Adjustment to Weather Normalization

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-2
Page 1 of 1

Line No.	Rate Class	UNS Gas Margin Weather Adjustment	Ratio of Weighted Average Annualized Customers	Staff Margin Weather Normalization	Adjustment to UNS Gas Proposed Weather Normalization
		(A)	(B)	(C)	(D)
1	Residential - 10	$ 369,269	1.004	$ 370,746	$ 1,477
2	Residential CARES - 12	$ 14,574	0.982	$ 14,312	$ (262)
3	Small Volume Commercial - 20	$ 95,408	1.009	$ 96,267	$ 859
4	Large Volume Commercial - 22	$ 67	1.000	$ 67	$ -
5	Irrigation - 60	$ 44	-	$ 44	$ -
6	Small Volume Public Authority - 40	$ 37,438	0.997	$ 37,326	$ (112)
7	Large Volume Public Authority - 42	$ 121	1.000	$ 121	$ -
8	Total	$ 516,921		$ 518,883	$ 1,962

Notes and Source

Col. A: UNS Gas proposed weather normalization adjustment
Col. B: Weighted average of Staff recommended annualized customers and UNS proposed annualized customers
Col. C: Col. A x Col. B
Col. D: Col. C - Col. A

FERC 480

UNS Gas, Inc.
Adjustment to Bad Debt Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-3

Line No.	Description	Amount	Reference
1	UNS Gas Adjustment to Bad Debt Expense	$ 317,758	A
2	Recommended Staff Adjustment to Bad Debt Expense	$ 319,021	B
3	Adjustment to Bad Debt Expense	$ 1,263	L2 - L1

Notes and Source
A: UNS Gas Filing, Schedule C-2, page 3, line 5

B: Per Company's workpapers showing calculation of Bad Debt Expense adjustment (except where noted)

		UNS Gas Bad Debt Adj.	**Staff Bad Debt Adjustment**	
4	Test Year Revenues	$ 136,799,000	$ 136,799,000	
5	Add: Late Fees and Miscellaneous Service Revenues	$ 1,446,000	$ 1,446,000	
6	Total	$ 138,245,000	$ 138,245,000	
	Rate Case Adjustments			
7	Customer Annualization	$ 1,680,578	$ 2,067,072	C
8	Weather Normalization	$ 1,826,135	$ 1,687,027	D
9	Reclass Related to Prior Periods (CARES Adjustment)	$ (203,181)	$ (203,181)	
10	Total Rate Case Adjustments	$ 3,303,532	$ 3,550,918	
11	Uncollectible Revenue Adjustment Base	$ 141,548,532	$ 141,795,918	L6 + L10
12	2 Year Average Retail Write Off Rate	0.51052%	0.51052%	
13	Pro Forma Bad Debt Expense	$ 722,634	$ 723,897	L11 x L12
14	Recorded Test Year Bad Debt Expense	$ 404,876	$ 404,876	
15	Staff Recommended Adjustment to Bad Debt Expense	$ 317,758	$ 319,021	L13 - L14
	Note C Customer Annualization			
16	Revenue	$ 725,682	$ 828,115	Sch. C-1
17	Gas Cost	$ 712,128	$ 795,387	Staff workpaper
18	PGA Adjustor	$ 388,325	$ 443,570	Staff workpaper
19	Total	$ 1,826,135	$ 2,067,072	
	Note D Weather Normalization			
20	Revenue	$ 516,921	$ 518,883	Sch. C-2
21	Gas Cost	$ 733,104	$ 735,952	Staff workpaper
22	PGA	$ 430,554	$ 432,192	Staff workpaper
23	Total	$ 1,680,579	$ 1,687,027	

FERC Account 904

UNS Gas, Inc.
Remove Depreciation & Property Taxes for CWIP

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-4

Line No.	Description	Account	Amount	Reference
1	CWIP Related Depreciation Expense	403	$ (196,266)	A&B
2	CWIP Related Property Taxes	408	$ (166,884)	A&B
3	Total Adjustments		$ (363,150)	

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 4, lines 6 and 7
B: Testimony of Staff witness Ralph Smith

UNS Gas, Inc.
Remove Amortization of Deferred GIS Cost

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount	Reference
1	Remove Company-proposed Amortization of Deferred GIS Cost	407	$ (299,023)	A

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 3, line 6

B: Amounts taken from UNS Gas Workpaper for GIS expenditures adjustment

	Per UNS Workpaper	2005 Cost		Pre-2005 Cost
FERC Account 874				
Materials & Supplies	$ (505)	$ -		$ (505)
Outside Services - Consultants	$ (746,792)	$ 133,238	*	$ (613,554)
Property Tax	$ (60)	$ -		$ (60)
Travel - Meals & Entertainment	$ (265)	$ 51		$ (214)
Pensions & Benefits Allocated	$ (6,994)	$ 688		$ (6,306)
Worker's Compensation	$ (14)	$ 2		$ (12)
Payroll Taxes - FICA	$ (2,312)	$ 198		$ (2,114)
Payroll Taxes - Unemployment	$ (366)	$ 50		$ (316)
Vacation & Sick Accrual	$ (563)	$ 563		$ 0
Wages - Regular	$ (32,074)	$ 3,452		$ (28,622)
Wages - Overtime	$ (2,138)	$ -		$ (2,138)
FERC 874 Total	$ (792,083)			$ (653,840)
FERC Account 920				
A&G Expense Transferred - UNSG	$ (22,922)	$ 400		$ (22,522)
A&G Expense Transferred - TEP	$ (25,362)	$ 3,108		$ (22,254)
FERC 920 Total	$ (48,284)			$ (44,775)
FERC 874 and 920 Total	$ (840,367)			$ (698,616)

* 2005 expenditures derived from Frontline Energy Services LLC invoices provided in response to RUCO 2.15

UNS Gas, Inc.
Incentive Compensation and SERP

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	Staff Adjustment to UES's Performance Enhancement Program (PEP)	$ (63,430)	A
2	Staff Adjustment to UES's Other Incentive Comp and SERP	$ (198,794)	B
3	Total Adjustment to Incentive Compensation Expense	$ (262,223)	
4	Adjustment to Taxes Other Than Income	$ (5,202)	A

Notes and Source

A: Per Company's workpapers showing calculation of Incentive Compensation adjustment (except where noted)

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	Staff Adjusted Amount
874	Distribution - Mains & Services Expense	$ 20,731	50%	10,366
878	Distribution - Meter Expense	$ 16,844	50%	8,422
887	Distribution - Maintenance of Mains	$ 12,957	50%	6,479
903	Customer Records/Collections Expense	$ 29,800	50%	14,900
920	Administrative & General Salaries	$ 46,527	50%	23,264
		$ 126,859		$ 63,430
408	Taxes Other Than Income Taxes	$ 10,403	50%	5,202

B: Per UNS Gas Inc.'s response to STF 5.72

FERC Acct	FERC Account Description	Company Amount	Disallowance Percentage	Staff Adjusted Amount
923	Supplemental Executive Retirement Plan (SERP)	$ 93,075	100%	$ 93,075
923	Officer's Long Term Incentive Plan	$ 108,920	50%	$ 54,460
923	Officer Portion of Performance Enhancement Plan (PEP)	$ 52,860	50%	$ 26,430
923	Deferred Compensation Plan	$ 11,315	50%	$ 5,658
923	Omibus Plan	$ 38,342	50%	$ 19,171
	Total	$ 304,512		$ 198,794

UNS Gas, Inc.
Emergency Bill Assistance Expense

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount	Reference
1	Increase to Emergency Bill Assistance Expense	903	$ 21,600	A

Notes and Source

A Testimony of Staff witnesses Ralph C. Smith and Julie McNeely-Kirwan

UNS Gas, Inc.
Remove Nonrecurring Severance Payment Expense

Test Year Ended December 31, 2005

Line No.	Description	Amount	Account	Reference
1	Adjustment to Remove Severance Accrual Adjustment	$ (52,388)	857	A

Notes and Source

A: UNS Gas workpapers used to calculate its payroll adjustment

UNS Gas, Inc.
Overtime Payroll Expense

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Overtime Expense	$ 1,070,133	A
2	Staff Recommended Overtime Expense	$ 947,123	B
3	Adjustment to Overtime Expense	$ (123,010)	L2 - L1

Notes and Source

A: UNS Gas workpaper used to calculate its payroll adjustment

B: Amounts taken from UNS Gas workpapers used to calculate its payroll adjustment

Line No.	Description	2004	2005	2 Year Average
4	Overtime Charged Directly to O&M - Classified	$ 450,802	$ 871,111	$ 660,957
5	Overtime Charged Directly to O&M - Unclassified	$ 330,584	$ 129,333	$ 229,959
6	Total Overtime Charged Directly to O&M	$ 781,386	$ 1,000,445	$ 890,915
7	Regular Annualized O&M Payroll	$ 5,472,931		
8	Adjusted 2005 Regular O&M Wages per Books	$ 5,148,145		
9	Increase to Regular O&M Payroll	1.06309		
10	Two Year Average Overtime Charged to O&M	$ 890,915		
11	Increase to Regular Payroll	1.06309		
12	Staff Recommended Increase to Overtime	$ 947,123		

UNS Gas, Inc.
Adjustment to Overtime Payroll Expense - Alternative Calculation

Docket No. G-04204A-06-0463
Schedule C-9
Page 2 of 2

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Total Overtime	$ 1,402,549	A
2	Staff Normalized Total Overtime	$ 1,220,536	B
3	Difference	$ (182,013)	L2 - L1
4	O&M Percentage	0.7630	C
5	Alternative Adjustment to Overtime Expense	$ (138,876)	

Notes and Source
A: UNS Gas workpaper used to calculate its payroll adjustment
B: Amounts taken from UNS Gas workpapers used to calculate its payroll adjustment

		2004	2005	2 Year Average
6	Overtime Charged Directly to O&M - Classified	$ 450,802	$ 871,111	$ 660,957
7	Overtime Charged Directly to O&M - Unclassified	$ 330,584	$ 129,333	$ 229,959
8	Overtime Charged to Non-O&M Accounts	$ 211,113	$ 303,260	$ 257,187
9	Total Overtime Charged Directly to O&M	$ 992,499	$ 1,303,705	$ 1,148,102
10	Regular Annualized O&M Payroll	$ 8,868,400		
11	Adjusted 2005 Regular O&M Wages per Books	$ 8,342,113		
12	Increase to Regular O&M Payroll	1.06309		
13	Two Year Average Overtime Charged to O&M	$ 1,148,102		
14	Increase to Regular Payroll	1.06309		
15	Staff Recommended Increase to Overtime	$ 1,220,536		

C:

16	Normalized Overtime Charged to O&M per Company	$ 1,070,133
17	Total Normalized Overtime per Company	$ 1,402,549
18	Percentage of Overtime Charged to O&M	0.7630

UNS Gas, Inc.
Payroll Tax Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-10

Line No.	Description	Amount	Reference
1	Adjustment to Remove Severance Related Payroll Tax	$ (4,008)	A
2	Adjustment to Reduce Overtime Related Payroll Tax	$ (9,348)	B
3	Total Adjustment to Payroll Tax	$ (13,356)	

Notes and Source

A:	**Severance Accrual Adjustment (Schedule C-8)**		
4	Severance Accrual Adjustment	$ 52,388	
5	OASDI Tax Rate	6.20%	
6	OASDI Payroll Tax Related to Severance Adjustment	$ 3,248	
7	Severance Accrual Adjustment	$ 52,388	
8	Medicare Tax Rate	1.45%	
9	Medicare Payroll Tax Related to Severance Adjustment	$ 760	
10	OASDI Payroll Tax Related to Severance Adjustment	$ 3,248	
11	Medicare Payroll Tax Related to Severance Adjustment	$ 760	
12	Total Severance Related Payroll Tax Adjustment	$ 4,008	L6 +L9
B:	**Overtime Adjustment (Schedule C-9)**		
13	Overtime Payroll Adjustment	$ 123,010	
14	Allocator of wages in excess of $94,200	0.00817 *	
15	Wages in excess of $94,200	$ 1,005	L13 x L14
16	Overtime Payroll Adjustment	$ 123,010	
17	Wages in excess of $94,200	$ 1,005	
18	OASDI Tax Base	$ 122,005	L16 - L17
19	OASDI Tax Rate	6.20%	
20	OASDI Payroll Tax Related to Overtime Adjustment	$ 7,564	
21	Overtime Payroll Adjustment	$ 123,010	
22	Medicare Tax Rate	1.45%	
23	Medicare Payroll Tax Related to Overtime Adjustment	$ 1,784	
24	Adjustment to Overtime Related Payroll Tax	$ 9,348	L20 + L23

* Allocator of wages in excess of $94,200 calculated as follows:

Amounts taken from UNS Gas Payroll Tax adjustment workpaper

25	UNS Gas Unclassified Payroll in excess of $94,200	$ 83,916	
26	Gross Annualized Payroll - per Company	$ 10,270,949	
27	Allocator of wages in excess of $94,200	0.00817	L25 / L26

UNS Gas, Inc.
Nonrecurring FERC Rate Case Legal Expense

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-11

Line No.	Description	Amount	Reference
1	Adjustment to Remove FERC Rate Case Legal Expense	$ (311,051)	A

Notes and Source

A: Per UNS Gas Inc.'s response to STF 5.91
El Paso Gas Allocation/Rate Case settlement negotiations
through law firm of Fleischman & Walsh PLC

	Invoice Amount
May 2005	$ 87,269
August 2005	$ 28,463
September 2005	$ 56,612
October 2005	$ 32,331
November 2005	$ 28,712
December 2005	$ 39,129
December 2005	$ 38,535
	$ 311,051

FERC Account 923

UNS Gas, Inc.
Property Tax Expense

Docket No. G-04204A-06-0463
Schedule C-12
Page 1 of 1

Test Year Ended December 31, 2005

Line No.	Description	Amount	Reference
1	UNS Gas Proposed Increase to Property Tax Expense	$ 1,591,370	A
2	Staff Proposed Increase to Property Tax Expense	$ 1,511,080	B
3	Adjustment to Property Tax Expense	$ (80,290)	L2 - L1

Notes and Source
A: UNS Gas Filing, Schedule C-2, page 5, line 7
B: Amounts taken from Company workpapers used to calculate its property tax expense adjustment

	Utility Plant in Service Taxes	Transmission	Distribution	General/ Intangible	Total
4	Total Net Plant in Service - Rate Base	$ 12,668,650	$ 148,702,079	$ 9,770,270	$ 171,140,999
5	Less: Licensed Transportation in Rate Base	$ -	$ -	$(3,224,086)	$ (3,224,086)
6	Less: Land Cost & Rights of Way in Rate Base	$ (69,665)	$ (200,495)	$ (144,835)	$ (414,995)
7	Less: Environmental Property in Rate Base	$ (553,351)	$ (2,868,087)	$ (345,452)	$ (3,766,890)
8	Plus: Land FCV Per Arizona Dept. of Revenue		$ 697,806		$ 697,806
9	Plus: Materials & Supplies in Rate Base		$ 2,039,798		$ 2,039,798
10	Plant in Service Full Cash Value	$ 12,045,634	$ 148,371,101	$ 6,055,897	$ 166,472,632
11	Assessment Ratio*	24.0%	24.0%	24.0%	24.0%
12	Taxable Value	$ 2,890,952	$ 35,609,064	$ 1,453,415	$ 39,953,431
13	Average Tax Rate	9.4747%	9.4747%	9.4747%	9.4747%
14	Property Tax	$ 273,909	$ 3,373,852	$ 137,707	$ 3,785,468
15	Environmental Property in Rate Base	$ 553,351	$ 2,868,087	$ 345,452	$ 3,766,890
16	Statutory Full Cash Value Adjustment	50%	50%	50%	50%
17	Environmental Full Cash Value	$ 276,676	$ 1,434,044	$ 172,726	$ 1,883,445
18	Assessment Ratio*	24.0%	24.0%	24.0%	24.0%
19	Taxable Value	$ 66,402	$ 344,171	$ 41,454	$ 452,027
20	Average Tax Rate	9.4747%	9.4747%	9.4747%	9.4747%
21	Property Tax	$ 6,291	$ 32,609	$ 3,928	$ 42,828
22	Total Property Taxes	$ 280,200	$ 3,406,461	$ 141,635	$ 3,828,296
23	Property Taxes on Leased Property	$ -	$ -	$ 25,629 a	$ 25,629
24	Total Property Tax Expense	$ 280,200	$ 3,406,461	$ 167,264	$ 3,853,925
25	Less: Recorded Property Taxes Excluding Call Center	$ (135,825)	$ (2,082,996)	$ (124,024)	$ (2,342,845)
26	Property Tax Expense Adjustment	$ 144,375	$ 1,323,465	$ 43,240	**$ 1,511,080**

a: Property Tax for Leases calculated as follows (amounts taken from Company workpaper)

	Cottonwood Lease	Primary Value	Secondary Value	Total
27	Full Cash Value	$ 795,459	$ 1,016,515	
28	Assessment Ratio*	24.0%	24.0%	
29	Taxable Value	$ 190,910	$ 243,964	
30	Tax Rate	8.7284%	1.8218%	
31	Property Tax	$ 16,663	$ 4,445	$ 21,108
	Nogales Lease			
32	Full Cash Value	$ 397,182		
33	Assessment Ratio*	24.0%		
34	Taxable Value	$ 95,324		
35	Tax Rate	11.8563%		
36	Property Tax	$ 11,302		
37	Percentage Allocated to UNS Gas	40%		
38	Property Taxes Allocated	$ 4,521		$ 4,521
39	Total Lease Taxes			$ 25,629

* 2007 Arizona Statutory Assessment Ratio 24.0%

FERC 408

UNS Gas, Inc.
Worker's Compensation Expense

Test Year Ended December 31, 2005

Line No.	Description	Account	Amount	Reference
1	Adjustment to Worker's Compensation Expense	925	$ (34,234)	A&B

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 2, line 5
B: Testimony of Staff witness Ralph Smith

UNS Gas, Inc.
Membership and Industry Association Dues

Test Year Ended December 31, 2005

Line No.	Vendor	Amount	FERC Account
1	American Gas Association	$ 41,854	930
2	Less 40% Related to Lobbying & Advertising*	40%	
3	Adjusted American Gas Association	16,742	930
4	Arizona Utility Group	$ 500	930
5	Arizona Utility Investors Association	$ 2,500	930
6	Chino Valley Area Chamber of Commerce	$ 215	930
7	Coconino County Clerks of Superior Court	$ 18	921
8	Exchange Club	$ 375	921
9	Flagstaff Chamber of Commerce	$ 2,378	921
10	IBA Publishing Inc.	$ 325	930
11	Kingman Chamber of Commerce	$ 386	921
12	Kingman Rotary Club	$ 458	921
13	Mayer Area Chamber of Commerce	$ 72	930
14	Prescott Chamber of Commerce	$ 386	930
15	Prescott Valley Chamber of Commerce	$ 550	930
16	Seligman Chamber of Commerce	$ 40	930
17	Show Low Girls Soccer Booster Club	$ 25	930
18	Show Low Main Street	$ 375	930
19	U.S. Mexico Border Counties Coalition	$ 250	921
20	USDA Forest Service	$ 173	930
21	White Mountain Regional Development Corp.	$ 1,100	930
22	Total Membership and Industry Association Dues	$ 26,868	

		Total From Above	Adjustment
23	Total Amount Recorded in Account 921	$ 23,003	$ (23,003)
24	Total Amount Recorded in Account 930	$ 3,865	$ (3,865)
25	Total	$ 26,868	$ (26,868)

Notes and Source

Amounts taken from UNS Gas response to STF 5.61

* Percentage derived from NARUC Audit Reports on AGA Expenditures for 1998 and 1999 issued January 2000 and June 2001, respectively

UNS Gas, Inc.
Fleet Fuel Expense

Test Year Ended December 31, 2005

Line No.	Description		Amount	Reference
1	UNS Gas Adjustment to Fleet Fuel Expense	$	73,726	A
2	Staff Recommended Pro Forma Adjustment to Fleet Fuel Expense	$	21,287	B
3	Adjustment to Fleet Fuel Expense	$	(52,439)	L2 - L1

Notes and Source

A: UNS Gas Filing, Schedule C-2, page 3, line 9

B: Per Company's workpapers showing calculation of Fleet Fuel Expense adjustment (except where noted)

4	Average operational FTE count for 2005		123.58	
5	Average technical FTE count for 2005		24.83	
6	Average construction FTE's for 2005		148.42	L4 + L5
7	2005 miles driven		2,228,658	
8	2005 mileage per Average Construction FTE		15,016	L7 / L6
9	2 month Average Construction FTE's for 2006		158	
10	Assumed 2006 mileage with 1st quarter staffing levels		2,365,055	L8 x L9
11	2005 Actual miles/gallon		9.60	
12	Calculated gallons purchased		246,360	L10 / L11
13	Average cost of fuel for October 2006 through January 2007	$	2.26	Note C
14	Cost of calculated gallons purchased	$	556,773	L12 x L13
15	Dollars purchased through Pro-Cards during 2005	$	37,491	
16	Pro forma fuel expenditures	$	594,264	L14 + L15
17	Test year expenditures	$	565,263	
18	Pro forma expenditure adjustment	$	29,001	L16 - L17
19	Percentage transportation allocation to O&M		73.4%	
20	Staff recommended pro forma adjustment to Fleet Fuel Expense	$	21,287	

C Cost of fuel from a Three Month Average Retail Price Chart through January 17, 2007 taken from ArizonaGasPrices.com

UNS Gas, Inc.
Postage Expense

Docket No. G-04204A-06-0463
Schedule C-16

Test Year Ended December 31, 2005

Line No.	Description	Amount		Reference
1	UNS Gas Annualized Postage Expense	$ 529,380		A
2	Staff Annualized Postage Expense	$ 414,285		B
3	Adjustment to Postage Expense	$ (115,095)	a	L2 - L1

Notes and Source

A: UNS Gas workpaper used in calculating its Postage Expense adjustment

B: **Staff recommended Postage Expense Annualization**

Test Year Postage Expense	$ 386,673	
Postage increase effective January 8, 2006 ($.02 / $.37)	$ 1.05	
Increased Postage Expense	406,007	
Ratio of Weighted Average Annualized Customers	1.02039	b
Annualized Postage Expense per Staff	$ 414,285	

a: Allocation of Staff adjustment to FERC accounts

FERC 903	$ (109,455)	95.1%
FERC 921	$ (5,640)	4.9%
	$ (115,095)	100.0%

b: TY average and year end customers derived from the following rate classes per UNS Gas response to STF 11.10:

	Average	Dec. 2005
Residential - 10	118,821	121,125
Residential CARES -12	5,264	5,556
Small Volume Commercial - 20	10,849	11,017
Large Volume Commercial -22	10	11
Small Volume Public Authority - 40	1,042	1,051
Large Volume Public Authority - 42	6	5
	135,992	138,765

Additional Postage Expense through Customer Annualization 1.02039

UNS Gas, Inc.
Interest Synchronization

Test Year Ended December 31, 2005

Docket No. G-04204A-06-0463
Schedule C-17

Line No.	Description		Amount	Reference
1	Adjusted rate base	$	154,541,358	Schedule B
2	Weighted cost of debt		3.65%	Schedule D
3	Synchronized interest deduction	$	5,640,760	Line 1 x Line 2
4	Synchronized interest deduction per UNS Gas	$	5,334,825	Note A
5	Difference (decreased) increased interest deduction	$	305,935	Line 3 - Line 4
6	Combined federal and state income tax rates		38.598%	STF 5.76, item 6
7	Increase (decrease) to income tax expense	$	(118,085)	

Notes and Source

A RUCO 1.10 2005 UNSG Lead-Lag Summary.xls
Also, UNS Gas filing, Schedule B-5, page 3 of 3, line 18

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31,1999)

JUNE 2001

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005

Telephone No. (202) 1898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER **31,1999**

EXPENSE CATEGORY	PERCENTAGE
Public Affairs	15.43%
Communications	11.64%
Media Communications:	
Commercial Equipment	4.47%
Environmental	0.74 %
Promotional	0.74%
Residential Equipment	2.96%
Corporate Affairs & International	11.30%
General Counsel & Corporate Secretary	4.02%
Regulatory Affairs	11.20%
Marketing Services	15.02%
Operating & Engineering Services	14.70%
Policy & Analysis	12.07%
Industry Finance & Admin. Programs	2.94 %
General & Administrative Expense	0.00%
TOTAL	107.23% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1999

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (5)	Adjusted Net Expense	% of Dues
03	Public Affairs	4,147,682	3, 4	(1,690,669)	455,752	2,912,765	15.43%
03	Communications		4	1,698,695	498,479	2,197,174	11.64%
08	Media Communications						
	Commercial Equipment	759,932	1,2	61,868	21,400	843,200	4.47%
	Environmental	126,708	1,2	10,316	3,568	140,592	0.74%
	Promotional	126,708	1,2	10,316	3,568	140,592	0.74%
	Residential Equipment	503,934	1,2	41,027	14,191	559,152	2.96%
06. 16	Corporate Affairs and International	1,483,688	3	(5,217)	655,144	2,133,615	11.30%
05	General Counsel & Corp. Secretary	588,436	3		170,907	759,343	4.02%
09	Regulatory Affairs	1,492,676	3	194,393	427,268	2,114,337	11.20%
08	Marketing Services	4,654,503	1, 2	(2,302,920)	484,237	2,835,820	15.02%
14	Operating & Engineering Services	1,949,534			826,051	2,775.585	14.70%
07	Policy & Analysis	1,374,743	1	277.704	626,659	2,279,106	12.07%
12	Industry Finance & Admin. Programs	498,349			56,969	555,318	2.94%
01.10.11	General & Administrative Expense	4,247,002	3	(2,809)	(4,244,193)		0.00%
	Grand Total	21,953,895		$ (1,707,296)	$ -	$ 20,246,599	107.23%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 Breakout of communications portion of division expenses
5 G&A allocated on basis of equivalent full-time employees during 1999.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1999

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
	Public affairs provides members with information on legislative developments: prepares testimony, comments, and filings regarding legislative activities; lobbies on behalf of the industry.
08	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
	Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
	Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applicationsof specific equipment.
	Institutional - to enhance the image of the natural gas industry as a business entity.
	Power Generation Natural Gas Equipment - explains cost-savings. energy-savings and other benefits provided by specific equipment for generating power.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
12	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.

05 General Counsel & Corporate Secretaw provides legal counsel to the Association

06 Corporate Affairs provides opportun'ities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

09 Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

08 Market Development assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Donna's Copy

LF-111

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 1998)

JANUARY 2000

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue, N.W., Suite 200
Washington, D.C. 20005

Telephone No. (202) 898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 1998

EXPENSE CATEGORY	PERCENTAGE
Communications	10.27%
MEDIA COMMUNICATIONS:	
Commercial Equipment	5.96%
Environmental	3.37%
Industrial Equipment	1.36%
Promotional	1.46%
Residential Equipment	8.40%
Finance & Administration Services	12.17%
General Counsel & Corporate Secretary	5.54%
Government Relations	23.86%
Marketing Services	16.20%
Meeting Services	-0.18%
Operating & Engineering Services	4.90%
Planning & Analysis	9.51%
General & Administrative Expense	0.00%
TOTAL	102.82% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1998

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (4)	Adjusted Net Expense	% of Dues
03	Communications	1,561,612	2	(2,679)	430,782	1,989,715	10.27%
13	Media Communications						
	Commercial Equipment	1,105,739	1,2	31,943	17,848	1,155,530	5.96%
	Environmental	625,598	1,2	18,072	10,098	653,768	3.37%
	Industrial Equipment	252,954	1,2	7,307	4,083	264,344	1.36%
	Promotional	270,820	1,2	7,823	4,372	283,015	1.46%
	Residential Equipment	1,557,378	1,2	44,990	25,139	1,627,507	8.40%
06	Finance & Administration Services	1,797,937	3	(13,893)	574,377	2,358,420	12.17%
05	General Counsel & Corp. Secretary	938,797	3	(8,566)	143,594	1,073,825	5.54%
09	Government Relations	3,802,555	3	22,459	800,025	4,625,039	23.86%
08	Marketing Services	2,693,462	1	(107,456)	553,863	3,139,869	16.20%
04	Meeting Services	(34,155)		-	-	(34,155)	-0.18%
14	Operating & Engineering Services	661,825		-	287,188	949,013	4.90%
07	Policy & Analysis	1,392,718		-	451,296	1,844,014	9.51%
01,10,11	General & Administrative Expense	3,302,665		-	(3,302,665)	0	0.00%
	Grand Total	19,929,905		$ 0	$ 0	$ 19,929,905	102.84%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 G&A allocated on basis of equivalent full-time employees during 1997.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1998

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
13	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
	Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
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	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
06/ 16	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.
05	General Counsel & Corporate Secretary provides legal counsel to the Association.
09	Government Relations provides members with information on legislative and regulatory developments; prepares testimony, comments, and filings regarding legislative and regulatory activities; lobbies on behalf of the industry.
08	Marketing assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

04 Meeting Services and Membership Services provides support services for committee meetings and conferences. In addition, coordinates services provided to members.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Excerpt from Florida PSC City Gas Company rate case 01152004

State of Florida

Public Service Commission

Capital Circle Office Center 2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE:DECEMBER 23, 2003

TO:DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

FROM:DIVISION OF ECONOMIC REGULATION (BRINKLEY, BAXTER, DRAPER, GARDNER, HEWITT, KAPROTH, KENNY, LESTER, LINGO, C. ROMIG, SPRINGER, STALLCUP, WHEELER, WINTERS)
DIVISION OF COMPETITIVE SERVICES (MAKIN)
OFFICE OF THE GENERAL COUNSEL (JAEGER)

RE:DOCKET NO. 030569-GU - APPLICATION FOR RATE INCREASE BY CITY GAS COMPANY OF FLORIDA.

AGENDA:01/06/04 - REGULAR AGENDA - PROPOSED AGENCY ACTION - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES:5-MONTH EFFECTIVE DATE: JANUARY 15, 2004 (PAA RATE CASE)

SPECIAL INSTRUCTIONS:NONE

FILE NAME AND LOCATION:S:\PSC\ECR\WP\City Gas 030569-GU\
Final.RCM
Final Attachments 1-5.123
Final Attachments 6A-7P.123
Final Attachment 8.xls

ISSUE 39: Is City Gas's $(2,847) adjustment to Account 921, Office Supplies and Expenses, for American Gas Association membership dues appropriate?

RECOMMENDATION: No. Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for American Gas Association membership dues related to charitable contributions and advertising that is not informational or educational in nature. (C. ROMIG)

STAFF ANALYSIS: On MFR Schedule G-2, Page 17 of 34, the Company included $1,966,495 in its Account 921, Office Supplies and Expense for the 2003 interim year. Included in this amount is $39,277 related to American Gas Association (AGA) membership dues. This was inflated for customer growth and general inflation of 1.0232 to $40,188. On MFR G-2, Page 2 of 34, it removed $2,847 that was labeled as "attributable to lobbying." This represents an adjustment of 7.08%.

In City Gas's last rate case, In re: Request for rate increase by City Gas Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. In re: Application for a rate increase by City Gas Company of Florida, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

Attachment RCS-5
Copies of UNS Gas' Responses to Data Requests Referenced in Direct Testimony and Schedules of
Ralph C. Smith

Data Request No.	Subject	Page(s)
RUCO 2.15	Geographic Information System (GIS)	2-4
RUCO 1.10	Rate Base - GIS Deferral, Memo dated October 3, 2005, 2003-05 UNS Gas "GPS and Locate" Costs	5-11
STF 5.76	Errors in Filing Information	12-23
STF-5.72	Employee Benefits	24-28
STF 11.5 (c)	Incentive Compensation	29-30
STF 5.91	Legal Expense	31-32
RUCO 6.09	Proforma Adjustment Worker's Compensation Expense	33-34
RUCO 6.06	Proforma Adjustment Worker's Compensation Expense	35
STF 16.1	American Gas Association Dues	36-40
STF 5.28	Cost of Removal	41-42
STF 13.2	Cost Studies/Economic Analysis	43-44
STF 13.6	Incremental Contribution Study	45
STF 13.7	Change to Section 6.B.2b, impact on customers	46
STF 13.8	Change to Section 10C: Alignment Proposal, revision to billing terms	47
STF 13.9 (c)	Change to Section 10C: Due dates, late penalty charges	48-50
STF 13.10	Change to Section 10J, Electronic Billing	51-52
STF 13.11 (d)	Change to Section 11, Termination notice	53-55
RUCO 1.10	Cash Working Capital Lead/Lag Study Summary	56-57
STF 5.36	Accumulated Deferred Income Taxes	58-59
STF 11.10	Number of Customers by rate class	60-61
	Total Pages Including this Page	61

**UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
RUCO'S SECOND SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463**

October 25,2006

2.15 Geographic Information System (GIS) Please provide the following information regarding the GIS:

a) Date the GIS entered service;

b) Account where the GIS resides (include an explanation of the logic for the account chosen);

a) Original cost of GIS;

d) Indicate if the GIS is being depreciated or amortized, and if so, at what rate, if not, why not;

e) Copy of all invoices that comprise the $897,068 in costs; and

e) Accumulated amortization or depreciation balance at 12-31-05.

RESPONSE: UNS Gas is still compiling information and the response will be provided at a later date.

RESPONDENT: Carl Dabelstein

WITNESS: Karen Kissinger and Dallas Dukes

SUPPLEMENTAL RESPONSE:

a) The GIS entered service on July 1,2001.

b) The GIS resides in Account 391 per FERC Uniform System of Accounts.

c) The original cost of GIS was $1,158,035.

d) The GIS is depreciated at a rate of 13.92%.

e) See Bates Nos. UNSG (0463) 00112 to UNSG (0463) 00178 for copies of the invoices that comprise the $897,068 in costs. They total $746,776 of the total $897K sought for recovery. The difference represents labor, labor-related costs, and overheads.

f) The accumulated amortization balance at 12-31-05 was $718,676.

RESPONDENT: **Carl** Dabelstein

WITNESS: Karen Kissinger

TEP. Inc.
UNS Gas "GPS and Locale" Task Analysis
813112005

			Expenditures by Year			
Project #	Task #	Task Description	2003	2004	2005	Total
250912C	DA10000	Locate 6 GPS Existing Mains and Services	104,963.27	601,320.62	23,058.13	729,342.02
250912A	DA10009	Locate & GPS Existing Mains and Services, Kingman & Havasu, Flag Admin		1,950.04	165,671.03	167,621.07
		Total	104,963.27	603,270.66	188,729.16	896,963.09

Invoices Provided

250912C	DA10000	Front Line Energy Costs	585,316.53	80%	of total Task Costs
250912A	DA10009	Front tine Energy Costs	161,460 00	96%	of total Task Costs
			746.776.53	83%	

DATE: October 3, 2005

TO: UNS Gas File

FROM: Steve K. Sims

Background

In 2003 UniSource Energy (UNS) created three subsidiaries to handle the acquisition of the Arizona gas and electric utility properties owned by Citizens Communications. The three subsidiaries are UniSource Energy Service (UES), a holding company, which owns the stock of UNS Gas and UNS Electric, the operating companies. On August 11, 2003, UNS Gas and UNS electric acquired the utility assets from Citizens. Absent an ACC order to the contrary, when a company acquires the operating assets of a utility regulated by the ACC, the acquirer is required to follow the regulatory accounting procedures used by the predecessor company.

UNS is a public company filing quarterly Forms 10-Q and annual reports on Form 10-K with the SEC. UES quarterly and annual financial data is reported in the segment information included in the Forms 10-Q and in the Form 10-K. UNS Gas prepares annual audited financial statements which are provided only to their lenders.

202

Issue

UNS Gas undertook a project to locate and GPS all of their existing service lines during 2003-2005 in order to update the data in the UNS Gas Global Information System (GIS). These costs were accounted for as capital costs and partially placed-in-service in 2005 with an in-service date of 12/31/03 with catch-up depreciation of approximately $50,000 recognized as of 8/31/05. The total cost of the project was $897,000 with approximately 83% of the cost, or $747,000, paid to Front Line Energy for locating and GPS'ing the lines. This project took place as a result of an Arizona Corporation Commission (ACC) compliance audit. The ACC compliance audit found that:

Maps available at the time of the audit and used by locating, leak survey, construction and emergency personnel fail to include all service lines.

Per discussion with Carl Dabelstein, Director of Regulatory Accounting, absent an ACC order to defer any costs the accounting treatment of the costs would be consistent with Generally Accepted Accounting Principles (GAAP). The FERC Uniform System of Accounts (USOA) does not specifically prescribe a procedure to be used in accounting for the costs of developing computer software, however, in its Order on Accounting for Pipeline Assessment Costs (copy attached) issued in Docket No. A105-1-000 on June 30, 2005, a specific reference to SOP 98-1 appears in footnote 8 on page 8 thereof. At the fall 2005 meeting of the NARUC Accounting Committee, Carl Dabelstein broached the subject of software development cost accounting with current FERC Chief Accountant, James Guest. Mr. Guest confirmed that, although the accounting has not yet been incorporated into the FERC USOA, that it is his position that companies subject to FERC regulation should follow the requirements of SOP 98-1.

SOP 98-1 – Accounting for the Costs of Computer Software Developed or Obtained for Internal Use – Paragraph .22 states:

The process of data conversion from old to new systems may include purging or cleansing of existing data, reconciliation or balancing of the old data and the data in the new system, <u>creation of new/additional data,</u> and conversion of old data to the new system. Data conversion often occurs during the application development stage. Data conversion costs, except as noted in Paragraph .21, <u>should be expensed as incurred.</u>

1.

The key guidance has been underlined. Any creation of new data should be expensed as incurred.

The misstatement to the financial statements as of December 31, 2004 is as follows:

UNS Gas/UES/UNS
- Overstatement of Total Utility Plant -$872,000
- Overstatement of Accumulated Depreciation and Amortization - $0
  (Accumulated Depreciation and Amortization is $0 due to the asset not being placed-in-service prior to 2005)
- Overstatement of cumulative Net Income of $527,000 of which $63,000 relates to 2003
- Understatement of cumulative Other Operations & Maintenance - $872,000

In accordance with Accounting Principles Board No. 20, *Accounting Changes,* (APB20) the misstatement is considered to be a correction of an error and should be accounted for as such. Paragraph 38 of APB 20 provides guidance on evaluating materiality of errors and states in part,

> "...a number of factors are relevant to the materiality of ... corrections of errors, in determining both the accounting treatment of these items and the necessity for disclosure. Materiality should be considered in relation to both the effects of each change separately and the combined effect of all changes. If a change or correction has a material effect on income before extraordinary items or on net income of the current period before the effect of the change, the treatments and disclosures described in this Opinion should be followed. Furthermore, if a change or correction has a material effect on the trend of earnings, the same treatments and disclosures are required. A change which does not have a material effect in the period of change but is reasonably certain to have a material effect in later periods should be disclosed whenever the financial statements of the period of change are presented."

Discussion

The following analysis reflects UNS, UES, and UNS Gas consolidated financial information. UNS Gas is a reportable business segment and contributes approximately 11% to UNS's consolidated operating revenues and comprises approximately 6.3% of its consolidated assets.

Financial Statements

In considering the materiality of the misstatement both quantitative and qualitative aspects need to be considered.

UNS Gas

The income statement and balance sheet misstatements are attributable to the following years (in thousands):

	Other O&M Under Statement	Other O&M as Reported (Unadjusted)	% of Reported Other O&M	Net Income Over/(Under) Statement	Net Income as Reported (Unadjusted)	% of Reported Net Income
2003	$ 105	$ 8,382	1.25%	$ 63	$1,077	5.85%
2004	767	23,009	3.33%	463	5,703	8.12%
Total Misstatement	$ 872	$31,391	2.78%	$ 526	N/M	N/M

2.

	December 31, 2004			
	Unadjusted	*Aggregate Misstatement*	*As Adjusted*	*% of Adjusted Amount*
Total Utility Plant	$ 167,871	$ (872)	$166,999	0.52%
Accumulated Depreciation and Amortization	(6,893)	0	(6,893)	0%
Total Utility Plant - Net	160,978	(872)	160,106	0.54%
Total Assets	201,353	(872)	200,481	0.44%

UNS Gas financial results are reported annually in audited financial statements prepared for lenders. The key impact to be considered is UNS Gas' ability to meet the financial covenants of the credit facilities and not the results of operations or the net income contribution to UNS Shareholders. As discussed below, the ability to satisfy these covenants has not been meaningfully affected by the misstatement. Based on the foregoing, the misstatements to the annual 2003 and 2004 financial statements are deemed to be immaterial.

UES

The income statement and balance sheet misstatements are attributable to the following years (in thousands):

	Other O&M Under Statement	Other O&M as Reported (Unadjusted)	% of Reported Other O&M	Net Income Over/(Under) Statement	Net Income as Reported (Unadjusted)	% of Reported Net Income
2003	$ 105	$ 16,973	0.62%	$ 63	$3,010	2.09%
2004	767	46,984	1.63%	463	10,047	4.61%
Total Misstatement	$ 872	$63,957	1.36%	$ 526	N/M	N/M

	December 31, 2004			
	Unadjusted	*Aggregate Misstatement*	*As Adjusted*	*% of Adjusted Amount*
Total Utility Plant	$284,271	$ (872)	$283,399	0.31%
Accumulated Depreciation and Amortization	(19,789)	0	(19,789)	0%
Total Utility Plant - Net	264,355	(872)	263,483	0.33%
Total Assets	336,131	(872)	335,259	0.26%

UES annual audited financial statements are provided to the lenders of UNS Gas and UNS Electric. UNS Gas financial results are also reported quarterly and annually in the segment information provided in the Forms 10-Q and Form 10-K. The annual information provided in the Form 10-K only reports Net Income. The segment footnotes in the UNS Form 10-Q report Income Before Income Taxes and Net Income for the quarterly and year-to-date periods appropriate for the quarter, and Total Assets as of the end of the quarter. Based on the above with O&M being understated by a maximum of 1.63%, a Net Income maximum misstatement of 4.61% and a Total Asset misstatement of .26%, it is not believed that any segment differences would have misled investors or changed their investment decision. The key impact to be considered is UNS Gas' ability to meet the financial covenants of the credit facilities, discussed below.

UNS

The income statement and balance sheet misstatements are attributable to the following years (in thousands):

	Other O&M Under Statement	Other O&M as Reported (Unadjusted)	% of Reported Other O&M	Net Income Over/(Under) Statement	Net Income as Reported (Unadjusted)	% of Reported Net Income
2003	$ 105	$ 216,323	0.05%	$ 63	$46,470	0.14%
2004	767	252,711	0.30%	463	45,919	1.01%
Total Misstatement	$ 872	$469,034	0.19%	$ 523	N/M	N/M

	December 31, 2004			
	Unadjusted	*Aggregate Misstatement*	*As Adjusted*	*% of Adjusted Amount*
Total Utility Plant	$3,873,467	$ (872)	$3,872,595	0.02%
Accumulated Depreciation and Amortization	(1,348,017)	0	(1,348,017)	0%
Total Utility Plant - Net	2,081,137	(872)	2,080,265	0.04%
Total Assets	3,175,518	(872)	3,174,646	0.03%

Based on the foregoing, the misstatements to the 2003 and 2004 UNS income statements are deemed to be immaterial. The misstatements attributable to the quarterly periods for UNS (the impacts of the misstatement in each quarterly period beginning in the third quarter of 2003 through 2004 are outlined in Appendix A) are also considered to be immaterial as Net Income is not misstated in any quarterly period more than 1.29%. Based on an annualized quarterly amount, the 2004 misstatement of Net Income is only 1.01%. Based on these considerations, the misstatement to the UNS income statement attributable to 2003 and 2004 are deemed to be immaterial.

Based on the foregoing, the misstatements to the December 31, 2004 balance sheets are deemed to be immaterial as the misstatement to Total Utility Plant was .02% and to Total Assets of .03%

Impact on Third Quarter 2005

As provided for in Staff Accounting Bulletin Topic 5.F., we must consider the impact on the third quarter and nine months ended September 30, 2005 results for UNS if the misstatement is corrected in September 2005. The misstatement amounts shown below are net of the catch-up depreciation that has been recognized for the portion of the asset that was placed in-service on July 19, 2005 with an in-service date of 12/31/03.

UNS Gas is a small segment of UNS Consolidated at 6.3% of total assets. The third quarter 10-Q segment disclosure for UNS Gas net income is $2,000,000 which includes this write-off. As such, the write-off amount is considered immaterial to the segment disclosure. Year-end 2005 impact of this adjustment combined with other adjustments for UNS Gas will be addressed in a separate memo.

UNS	3rd Quarter 2005 Projected Unadjusted	Misstatement	As Adjusted	% of Adjusted Amount
Other O&M	$56,703	$ 847	$57,550	1.47%
Total Operating Expense	286,571	847	287,418	0.29%
Operating Income	56,701	(847)	55,854	1.52%
Net Income	15,733	(542)	15,191	3.57%

UNS	Nine Months Ended September 30, 2005 Projected Unadjusted	Misstatement	As Adjusted	% of Adjusted Amount
Other O&M	$179,444	$ 847	$180,291	.47%
Total Operating Expense	763,569	847	764,416	0.11%
Operating Income	141,223	(847)	140,376	.60%
Net Income	21,418	(542)	20,876	2.60%

The quantitative effects on the quarterly and nine-month periods ended September 30, 2005 reflect a change from reporting approximately $21.4 million and $15.7 million of Net Income to reporting approximately $20.9 million and $15.2 million of Net Income, respectively. Further, as outlined above, the misstatements to Total O&M, Total Operating Expense and Operating Income are NOT considered quantitatively material as NONE of the impacts exceed 1.52%. The correction of the error in the third quarter does not result in a material impact on Net Income.

As previously noted, in evaluating the materiality of a misstatement, qualitative considerations need to be considered as well as the quantitative aspects. SEC Staff Accounting Bulletin 99 – Materiality (SAB 99) provides both quantitative and qualitative guidance as to whether a financial statement change should be considered material. In evaluating qualitative aspects, SAB 99 indicates that the registrant should consider whether the misstatement arises from an item capable of precise measurement or whether it arises from an estimate. In addition, SAB 99 asks the registrant to consider whether the misstatement or change has any of the following implications:

- Masks a change in earnings or other trends;
- Hides a failure to meet analysts' consensus expectations for the enterprise;
- Changes a loss into income or vice versa;
- Affects compliance with regulatory requirements;
- Affects compliance with loan covenants or other contractual requirements;
- Increases managements' compensation; or
- Conceals an unlawful transaction.

Due to the immateriality of the error to UNS, we do not believe that the error masks a change in earnings, does not hide a failure to meet analysts' consensus expectations for the enterprise, it does not change income into a loss, it does not affect compliance with regulatory requirements, it did not increase management compensation and does not conceal an unlawful transaction. The affect on compliance with loan covenants is discussed below.

5.

UNS Gas Debt Compliance

We have reconsidered UNS Gas interest coverage ratio, capitalization ratio and net worth tests related to all financial covenants of their credit agreements, noting that these adjustments would not have affected compliance with any of these loan covenants as follows:

- The interest coverage ratio is a ratio of EBITDA to Interest Expense (excluding the effect of Debt AFDC). EBITDA is overstated as a result of this misstatement. EBITDA before adjustment was $8M in 2003 and $24M in 2004. The pre-tax adjustment of $105K and $767K in 2003 and 2004, respectively, would not significantly affect the ratio.

- The capitalization ratio is a ratio of total indebtedness to total capitalization. Since total capitalization was overstated, this means that UNS Gas' debt as a percent of total capitalization would have increased in each period, had the adjustment been made in 2004. However, UNS Gas Total Assets misstatement of .26% would not have materially changed the ratio.

- UNS Gas actual net worth test compares actual net worth to a minimum amount. In all cases, although Net Income decreased after adjusting for the misstatement, the net worth amount would be lower in each period but would still have met minimum requirements.

There are no dividend restrictions or other contractual requirements that would have been affected by the misstatements. In each year, our performance would have been slightly worse. However, we were well within compliance with all applicable requirements, a slight decrease would have made no difference in the evaluation of UNS Gas, UES or UNS's operations. Further, it would not have been in management's personal interest to overstate earnings in any period nor would it have impacted their compensation. In addition, this error was not the result of any fraudulent activity or made in an attempt to conceal an unlawful transaction.

Summary of Financial Statement Impact

In addition, we considered financial measures that investors believe are significant and place reliance on in making their investment decisions. This includes not only GAAP measures such as Cash Flows from Operations and the Ratio of Earnings to Fixed Charges (RETFC), but certain non-GAAP measures such as Adjusted EBITDA as outlined in Item 6 of our 2004 Annual Report on Form 10-K. This change would not have any impact on Cash Flows from Operations or EBITDA and based on recalculating the RETFC, the misstatement did not have a significant or adverse impact on this measure. Accordingly, we do not believe that this change would have an impact on investor decisions. No qualitative considerations that would affect the decisions of a financial statement reader have been identified.

Based on the foregoing considerations, and also taking into account the following matters, the misstatement is not deemed to be qualitatively material for the quarter or nine months ended September 30, 2005: The misstatement does not mask any identifiable trends in UNS' third quarter earnings. Further, because of the seasonal nature of UNS's operations, projections provided to analysts are provided only on an annual basis. Analysts and investors are primarily concerned with the cash flows of the company and the misstatement has no effect on the reported or future cash flows. Further, to the extent that there are investors looking at earnings per share, there are many other variable factors in the operations of UNS that can have significant effects on EPS and we do not believe that the effect of recording the misstatement in the second quarter of 2005 masks any trends in EPS. Accordingly, we do not believe that the misstatement has a material impact on the quarter or nine months ended September 30, 2005.

Based on our consideration of both the quantitative and qualitative effects of the misstatement, we believe that the information above supports the conclusion that the financial statement differences are not material to the financial statements as of September 30, 2005 or for the quarterly period and nine months then ended. Note that ABP 28, *Interim Financial Reporting,* paragraph 29 requires disclosure of corrections that are material with respect to an interim period even though they are not material to the estimated income for the year or to the trend of earnings. Because the corrections are not considered material to the quarter and nine months ended September 30, 2005, no disclosures in our Third Quarter Report on Form 10-Q are considered necessary.

6.

Internal Controls

On June 5, 2003, the SEC issued final rules under Section 404 of the Sarbanes-Oxley Act requiring companies to file in their annual reports, a report of management on the company's internal control over financial reporting. Part of the required content in the report is a disclosure of any material weaknesses in the system. An internal control deficiency is a flaw in either the design or operation of a control policy or procedure that has a negative effect on this process. Consequently, we must determine if the internal control deficiency is inconsequential, significant or material.

As previously noted, the misstatement is not deemed to be material to the financial statements for the year or the quarter ended September 30, 2005. In addition, the misstatements were not intentional and have a nominal effect on earnings.

The Public Company Accounting Oversight Board (PCAOB) provides guidance for evaluating control deficiencies in Standard No. 2 as updated as of December 3, 2004 (AS2). Paragraph 23 of AS2 indicates that "The same conceptual definition of materiality that applies to financial reporting applies to information on internal control over financial reporting, including the relevance of both quantitative and qualitative consideration." In addition, we need to consider the likelihood that the deficiency could result in a misstatement and the magnitude of the potential misstatement. Several factors affect the likelihood including the nature of the related accounts, the cause of known exceptions, and the possible future consequences.

Based on review of the relevant considerations, we have concluded that an error of this kind is unlikely to happen again. The misstatement occurred due to a transfer of a task and the continued use of that task for cost accumulation from Citizens at acquisition. A second task for the work was created by Plant Accounting personnel prior to institution of the Capital Work Order Approval decision tree. The process of using the Capital Work Order Approval decision tree along with CON-GA-17 "Computer Software Costs" would have identified the work order as O&M and alerted the Plant Accounting personnel to the incorrect conversion and use of the previous work order. Steps have been taken to ensure that current Plant Accounting staff have been adequately trained on CON-GA-17 and its' implications when making the Capital vs O&M decision. During 2004, management evaluated and tested controls in place to ensure compliance with GAAP. Our testing of both the design and effectiveness of such controls noted no deficiencies.

Because the appropriateness of our accounting for the UNS Gas "GPS and Locate" costs was reconsidered in connection with UNS Electric's request to do the same task, our evaluation of the magnitude of a potential error should consider how in the absence of such analysis we would have identified the misstatement. Our current control processes require the completion of a Plant Accounting Work Order Creation - Capital Work Order Approval Decision Tree that is checked and reviewed for task creation. This review was not conducted in 2003 when the tasks were migrated from Citizens to TEP at the time of acquisition on August 11, 2003. Accordingly, in drawing a conclusion as to the maximum amount of potential misstatement we believe that the current process would have identified the task as O&M on the front end and appropriately charged to O&M.

Based on the foregoing, we do not believe that the control deficiency is material and therefore the deficiency does not constitute a material weakness. Note however, the deficiency is considered to be a significant deficiency and will be appropriately reported to the audit committee as well as the independent auditors.

Conclusion

We have carefully considered both quantitative and qualitative aspects of the misstatement of the UNS Gas "GPS and Locate" costs and believe that the error is not material to the respective financial statements for all periods considered. Accordingly, it is deemed acceptable to record the correcting adjustment in the third quarter of 2005.

cc: Peggy Denny, Karen Kissinger, Dave Grzybowski, Brian Hagues (PwC), David Eberhardt (PwC)

7.

**UNS GAS, INC.'S RESPONSES TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 8,2006**

STP 5.76 Filing Information. As the Company discovers errors in its filing identify such errors and provide documentation to support any changes. Please update this response as additional information becomes available.

RESPONSE: At the present time, UNS Gas has identified the following errors in its filing:

1. Exhibit TVL-2 to Mr. Tobin L. Voge's Direct Testimony should be replaced in its entirety with Exhibit TVL-2A, provided on the enclosed CD as STF 5.76 (EXHLBIT TVL-2A). The Throughput Adjustment (line 7 and line 9) should be a positive, not negative, number. The Exhibit is not identified by Bates numbers.

7 The O&M expenses referenced in Mr. James S. Pignatelli's Direct Testimony. page 3, line 24, should be $38,740,547, as presented in Schedule C-1, line 9.

3. The customer base referenced in Mr. Gary A. Smith's Direct Testimony, page 2, line 26, should be 131,474.

4. The targeted annual savings referenced in Mr. Smith's Direct Testimony, page 15, line 9, should be 36,056 therms.

5. Exhibit GAS-1 to Mr. Smith's Direct Testimony should be replaced in its entirety with Exhibit GAS-1 A, provided on the snclosed CD as STF 5.76 (EXHIBIT GAS-1 A). The Commercial HVAC Retrofit Program's Annual Therms should be 36,056, the TRC Ratio should be 1.46 and the PT Ratio should be 3.17. The Commercial & Industrial Gas Subtotal's Annual Therms should be 78,862, the TRC Ratio should be 1.36 and the PT Ratio should be 2.99. The Exhibit is not identified by Bates numbers.

6. On schedule A-3, the effective tax rate should be 38.598 percent times the taxable income as percent of 99.40. This would result in a gross conversion factor of 1.6370 rather than 1.6649. See STF 5.76 (6), Bates No. UNSG(0463)03778 to UNSG(0463)03779, on the enclosed CD for backup documentation.

7. Schedule B-5, line 19, "Revenue Taxes and Assessments," should be $11,966,406 as opposed to $18,788,535. This changes the cash working capital (Schedule B-5, line 20) to ($2,586,909) as opposed to ($3,230,886). This also changes pro forma current income taxes

**UNS GAS, INC.'S RESPONSES TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 8,2006**

(Schedule B-5, line 14) to ($1,212,062) as opposed to 3780
($1,203,222). See STF 5.76, Bates Nos. UNSG(0463)0~~3790~~ to
UNSG(0463)3782, on the enclosed CD for backup documentation.

8. In the Company's Schedule H support workpapers, Column 21, line 15, a negative $54,558 was inadvertently entered. The Residential rate impact was minimal. This was addressed in the Company's response to 2.17 in RUCO's second set of data requests.

RESPONDENT: Legal Department

EXHIBIT

TVL-2A

Example of Throughput Adjustment Calculation

Line	Residential (R-10 and R-12)	
1	Test Year Throughput (Therms)	70,234,286
2	Test Year Average Number of Customers	124,085
3	Test Year Use Per Customer (Line1/Line 2)	566.02
4	Hypothetical 2006 UPC (1)	560.92
5	Difference in UPC (Line 4 - Line 3)	(5.09)
6	Margin Rate (per Therm)	$0.1862
7	Throughput Adjustment (Line 2 x Line 5 x Line 6 x (-1))	$117,699
8	Projected 12 month Throughput (Therms) (2)	75,965,404
9	Throughput Adjustment per Therm (Line 7/Line 8)	$0.0015

Line	Small Volume Commercial (C-20)	
1	Test Year Throughput (Therms)	28,801,436
2	Test Year Average Number of Customers	10,849
3	Test Year Use Per Customer (Line1/Line 2)	2654.75
4	Hypothetical 2006 UPC (3)	2617.59
5	Difference in UPC (Line 4 - Line 3)	(37.17)
6	Margin Rate (per Therm)	$0.2637
7	Throughput Adjustment (Line 2 x Line 5 x Line 6 x (-1))	$106,329
8	Projected 12 month Throughput (Therms) (4)	30,259,509
9	Throughput Adjustment per Therm (Line 7/Line 8)	$0.0035

Line	Small Volume Public Authority (PA-40)	
1	Test Year Throughput (Therms)	5,743,485
2	Test Year Average Number of Customers	1,042
3	Test Year Use Per Customer (Line1/Line 2)	5511.98
4	Hypothetical 2006 UPC (5)	5407.25
5	Difference in UPC (Line 4 - Line 3)	(104.73)
6	Margin Rate (per Therm)	$0.2712
7	Throughput Adjustment (Line 2 x Line 5 x Line 6 x (-1))	$29,595
8	Projected 12 month Throughput (Therms) (6)	5,858,929
9	Throughput Adjustment per Therm (Line 7/Line 8)	$0.0051

Notes
(1) Decline of 0.9%, based on the average year over year change in residential UPC years 1996 to 2005.
(2) Based on a 4.0% annual growth rate.
(3) Decline of 1.4%, based on the average year over year change in total commercial UPC years 1996 to 2005.
(4) Based on a 2.5% annual growth rate.
(5) Decline of 1.9%, based on the average year over year change in total public authority UPC years '96 to 05
(6) Based on a 1.0% annual growth rate.

EXHIBIT

GAS-1A

Residential Programs

Programs by Market or Customer Segment	Program Name	Residential Electric Program Description	Proposed Average Annual Budget	Targeted Annual Savings	Benefit Costs Ratios
Residential Gas	Residential Furnace Retrofit	• Provides prescriptive incentives for residential single and multifamily home owners for energy efficiency improvements in residential gas fueled furnace applications. • Utilizes the existing UES online 'Residential Energy Advisor', or Department of Energy online energy audit, as part of the program application process. • Provide training, qualification and promotion of contractors who are knowledgeable and meet UES standards installing and operating high efficiency HVAC systems. • All residential structures in the UNSE and UNSG service territories served by UESG gas are eligible for the furnace efficiency measures. • Annual installation of approximately 800 furnaces with 90% or greater AFUE ratings.	$204,243	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 74,240	TRC Ratio = 1.26 PT Ratio = 2.23
	Residential New Construction	• Provides prescriptive incentives to home builders for installation of energy efficiency measures in new residential construction projects. • Provide educational and promotional pieces and design tools to assistance to developers of new residential structures and associated middle market trade allies (A&Es, contractors, etc.) with the installation of high-efficiency homes that meet or exceed the UNSG Efficient Home and ENERGY STAR program standards. • Uses the UNSG Efficient Home (Energy Star) program savings measures, plus additional appliance measures. • Provides incentives to builders to install Energy Star labeled dishwashers, clothes washers, and refrigerators. • All new single family and multifamily buildings in the UNSE and UNSG service territories are eligible. • Annual participation is estimated to be 5% of new units, or approximately 580 homes in 2007.	$418,201	Coincident Peak kW = 914 Annual kWh = 1,415,646 Annual Therms = 72,651	TRC Ratio = 1.98 PT Ratio = 4.06
		Residential Gas Subtotal	$622,444	Coincident Peak kW = 914 Annual kWh = 1,415,646 Annual Therms = 146,891	TRC Ratio = 1.[illegible] PT Ratio = 3.2[illegible]

Commercial Programs

Programs Organized by Market or Customer Segment	Program Name	Commercial Gas Program Description	Proposed Average Annual Budget	Targeted Annual Savings	Benefit Costs Ratios
C&I Gas	Commercial HVAC Retrofit	• Provides prescriptive incentives for business owners for energy efficiency improvements in gas fueled heating (space and water) applications. • Utilizes the existing UES online 'Business energy Advisor'. or Department ot' Energy online energy audit, as part of the program application process. • Provide training, qualification and promotions of contractors who are knowledgeable and meet UES standards • Panicipating allies will hc allowed to participate in a qualified allies referral program • The target marker includes all commercial facilities in the UNSE and UNSG service territories served by UESG gas are eligible for the efficiency measures • Annual participation is estimated at approximately 130 facilities.	$150,500	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 36,056	TRC Ratio = 1.46 PT Ratio– 3.17
	Commercial Gas Cooking Efficiency	• Provides prescriptive incentives for business owners for energy efficiency improvements in commercial gas fueled cooking applications. • The target market includes all commercial kitchens in the UNSE and UNSG acrvice territories served hy UNSG gas are eligible for the efficiency measures • The market for participating facilities in all UES service territories is estimated at 700 restaurants, and numerous kitchens located in schools, hospital, and lodging facilities.	$143.672	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 42,806	TRC Ratio = 1.16 PT Ratio = 2.81
		Commercial & Industrial Gas Subtotal	$204.1 72	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 78,862	TRC Ratio = 1.36 PT Ratio = 2 99

Revised 8/11/06

UNS Gas, Inc
Computation of Gross Revenue Conversion Factor
Test Year Ended December 31, 2005

Line No	Description		Percentage of Incremental Gross Revenues		Line No.
1	Gross Revenue		100.00%		1
2	Less: Uncollectible Revenue		0.51%		2
3	Taxable Income as a Percent		99.49%		3
4	Less: Federal (32.50%) and State Income (Combined Effective Tax Rate = 39.629%)	21%)	38.40%		4
5	Change in Net Operating Income		61.09%		5
6	Gross Revenue Conversion Factor		1.6370	(a)	6

38.598 1a
x .9949
38.40 %

(a) Line No 1 divided by line No. 5.

Supporting Schedules
N/A

Recap Schedules
A-1

STF 5.76-6

UNS Gas, Inc.
Tax Rnlc
2005 Test Year

G:\TAXSVCS\Rate Case\Rate Case - UNSG 2005 TY\[Schedule M Items xls]I - Current Income Taxes

Statutory AZ Corporate Tau Rate	6 968%
Statutory Federal Rate, Income < $10,000,000	34.000%
Less: State Tax Deduction Benefit	-2.370%
Federal Rnte after benefit of state deduction	31 630%
Total Combined Tax Rate	38.598% A

I.

UNS GAS
Cash Working Capital - Lead/Lag Study
For the Test Year Ending 12131105

Description (A)	FERC	Pro Forma Test Year Amount (B)		Revenue Lag Days (C)		Expense Lag Days (D)		Net Lag Days (Col. C - Col D) (E)	Lead/Lag Factor (Col. E/365) (F)	Cash Working Capital Required (Col F X Col.B) (G)
Operating Expenses:										
Non-Cash Expenses -										
Bad Debts Expense	904	$ 722,634	1a							
Depreciation	403/404	7,950,183	1.4a							$
Amortization	406	(729,791)	1.4b							
Deferred Income Taxes		3,178,719								
Other Operating Expenses -										
Salaries and Wages (UNSG Direct Employees)	Multi	7,287,745	2a	38.95	C	24.50	E.	14.45	0.0396	288,595
Incentive Pay (UNSG Direct Employes)	Multi	257,895	3a	38.95	C.	267.00	F	(228.05)	(0.6248)	(161,133)
Purchased Gas	Calc	78,101,248	4a	38.95	C	30.97	D.	7.98	0.0219	1,711,508
Office Supplies and Expenses	921	1,365,974	1.2a	38.95	C	20.72	H	18.23	0.0499	68,162
Injuries and Damages	925	574,128	1.2b	38.95	C.	64.75	H.	(25.80)	(0.0707)	(40,591)
Pensions and Benefits	926	2,452,071	1.2c	38.95	C	54.66	H	(15.71)	(0.0430)	(105,439)
Support Services - TEP (Direct Labor, Burdens, System Alloc.)	Note A	4,570,692	6a	38.95	C.	44.91	G	(5.96)	(0.0163)	(74,502)
Property Taxes	408	4,103,376	1.4c	38.95	C	213.00	I.	(174.05)	(0.4768)	(1,956,490)
Payroll Taxes	408	537,877	1.4d	38.95	C.	19.30	I.	19.65	0.0538	28,938
Current Income Taxes		(1,212,062)	2c	38.95	C.	41.42	I.	(2.47)	(0.0068)	8,242
Interest on Customer Deposits	431	170,459	1.4e	38.95	C	182.50	J.	(143.55)	(0.3933)	(67,042)
Other Operations and Maintenance	Multi	7,501,808	X	38.95	C.	53.10	K.	(14.15)	(0.0388)	(291,070)
Total Operating Expenses		116,832,955								
Other Cash Working Capital Elements:										
Interest on Long-Term Debt		5,357,726	2b	38.95	C.	91.62	J.	(52.67)	(0.1443)	(773,120)
Revenue Taxes and Assessments	Calc	$ 11,966,406	L	38.95	C.	76.25	I.	(37.30)	(0.1022)	(1,222,967)
Total Cash Working Capital			1a							$ (2,566,909) 2a

ProForma Operating Expenses - Excluding Income Taxes	$ 36,765,050	1.4f
Purchased Gas Lead/Lag Only	78,101,248	4a
ProForma Oper Exp To Tie Too - Excl Income Taxes	114,866,298	
Less 1a 1.4a 1.4b 2a 3a 4a, 1.2a 1.2b 1.2c 6a 1.4c 1.4d 1.4e	107,364,490	
Other O&M	$ 7,501,808	X.

STF 5.76 - 7

UNSG0463/03780

12/5/2006 8 52 PM

UNSG Rate Case
Simultaneous Equation

I = Synchronized Interest Deduction for Tax					
I =Weighted Cost of Debt x (Rate Base Excluding Working Capital + W)					
Weighted Cost of Debt =					3.30%
Rate Base Excluding Cash Working Capital					$ 164.942.248
I =	$	5,443,094.18	+	0.0330 W	

T = Current Income Taxes						
T = Effective Tax Rate x (Taxable Income Before 'I' - 'I') - Tax Credits						
Effective Tax Rate =						38.598%
Taxable Income Before Synchronized Interest =						$ 2,226,575
Tax Credits =						$ 3,500
Weighted Cost of Debt =						3.30%
T =	$	855,913.42	less	$ 2,100,925.49	less	0.01273734 W
T =	$	(1,245,012.07)	less	0.01273734 W		

W = Cash Working Capital					
W = CWC before I & T plus (L&L rate x 'I') plus (L&L rate x T)					
Cash Working Capital Excluding I & T =					$ (1.822.031)
Lead/Lag Factor Current Income Taxes =					(0 0068)
Lead/Lag Factor Interest Long Term Debt =					(0.1443)
W =	$	(2,599,003)	plus	(0.004762) W +	0.0000866 W
		1.0046753	W =	$ (2,599,003)	
W =		(2,586,909) a			

I =	$	5,443,094.18	plus	(85,367.99)
I =	$	5,357,726 b.		

T =	$	(1,245,012.07)	less	(32,950.34)
T =	$	(1,212,062) c.		

2.

UNS Gas
2006 Rate Case
Lead/Lag Study
Revenue Tax Calculation

	2005	
States Sales Tax - Billed	$ 7,110,645.39	1.2a
City Sales Tax - Billed	$ 1,008,729.11	2.2a
County Sales Tax - Billed	$ 864,480.57	3.2a
Sales Tax - Unbilled	Note A.	5.2a
Franchise Taxes	$ 2,308,006.05	6.2a
ACC Assessment	$ 379,665.78	7.2a
Total Revenue Taxes	$ 11,671,526.90	
Total Retail Revenue	$ 138,798,513.00	8a
Effective Revenue Tax Percentage	8.41%	

Test Year Retail Sales Revenue	$ 138,798,513.00	
Customer Annualization Adj - Margin	$ 725,682.00	9a
Est. Customer Annualization Adj. - Fuel Cost Rev	$ 1,100,453.00	9b
Weather Normalization Adj - Margin	$ 516,921.00	10a
Est. Weather Normalization Adj - Fuel Cost Rev	$ 1,163,658.00	10b
Estimated Pro Forma Retail Revenues	$ 142,305,227.00	
Effective Revenue Tax Percentage	8.41%	
Estimated Revenue Taxes	**$ 11,966,405.47**	a.

Note A. Initial preparer included gross sale tax accrued on unbilled. Net is the only amount applicable and is immaterial so I excluded sales tax on unbilled completely. The initial workpaper had an effective rate of 13.20% which was grossly overstated

Dallas Dukes

1.

**UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
January 5,2007**

STF 5.72 Employee Benefits. List and describe all retirement and incentive programs available to Company officers and employees.

a. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

b. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE: UNS Gas is in the process of gathering information and will provide the response to this data request as soon as the compilation is complete.

SUPPLEMENTAL RESPONSE: UniSource Energy Services ("UES") is a subsidiary of UniSource Energy Corporation and the parent company of UNS Gas.

Incentives

UNS Gas non-union employees participate in UES' Performance Enhancement Program ("PEP"). The structure determines eligibility for certain bonus levels by measuring UES' performance in three areas:

- financial performance,
- operational cost containment, and
- core business and customer service goals.

Levels of achievement in each area are assigned percentage-based "scores". Those scores are combined to calculate the final payout level. The amount made available for bonuses through this formula may range from 15% to 150 % of the targeted payment level.

The financial performance and operational cost containment components each make up 30% of the bonus structure, while the core business and customer service goals account for the remaining 40 %.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages as a percent of base salary range from 3% - 14% for regular non-union employees, and 25% - 80% for Managers and Officers. Bonus percentages as a percent of base salary are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a

**UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
January 5,2007**

payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Retirement Programs

UNS Gas employees are eligible to participate in the UES Pension Plan. For a description of this plan, please see STF 5.71 (Final UES Pension SPD v1 6-28-2004) on the enclosed CD. Additionally, UNS Gas employees are eligible to participate in the Tucson Electric Power Company ("TEP") 401(k) Plan as described below:

TEP 401(K) Plan

TEP's 401(k) Plan takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 50% of their pay, before any deduction for state or federal income taxes. The Company matches 50 cents on the dollar, up to the first 6% of pay saved, in the 401(k) Plan for UNS Gas employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection of professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching contributions are fully and immediately vested.

TEP Salaried Employees Retirement Plan ("Salaried Plan")
(This description is included because some cost is allocated back to UES for officer participation.)

The Salaried Plan provides an annual income based on the following formula:

1.6% *times* Final Average Pay

times

Years of Service (up to 25 years)

Final average pay is the average of basic monthly earnings, on the first of the month following the employee's birthday, during the five consecutive plan years in which basic monthly earnings were the highest, within the last 15 plan years before retirement.

Years of service are based on the employee's years and months of employment with TEP or a participating affiliated corporation. The

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS DOCKET NO. G-04204A-06-0463 January 5,2007

employee is vested in his or her retirement benefit after five years of service.

The maximum benefit available under the plan is an annual income of 40% of final average pay. Plan compensation for purposes of determining final average pay is limited to IRS compensation limits (Code Section) 401(a)(17). In addition, contributions to the UniSource Energy Corporation Management and Directors Deferred Compensation Plan ("Deferred Compensation Plan") are not considered eligible compensation under the Salaried Plan.

TEP Excess Benefit Plan ("Excess Plan")
(This description is included because some cost is allocated back to UES for officer participation).

The Excess Plan provides benefits to officers and other highly compensated employees in addition to the benefits payable under the Salaried Plan.

Compensation used to determine final average pay under the Salaried Plan is limited by annual IRS compensation limits (Code Section) 401(a)(17)), and is further reduced by any contributions to the Deferred Compensation Plan.

The Excess Plan retirement benefit is calculated using the Salaried Plan formula without regard to the IRS limits on compensation, voluntary salary reductions to the Deferred Compensation Plan, and the annual incentive bonus is added to the earnings rate.

The retirement benefit payable from the Excess Plan will be reduced by the benefit payable from the Salaried Plan.

UniSource Energy Corporation Management and Directors Deferred Compensation Plan ("Deferred compensation Plan")

The Deferred Compensation Plan allows participants (Directors, Officers and Managers) the opportunity to accumulate tax-deferred capital by allowing them to defer a portion of their pay on a pre-tax basis.

Salary and Bonus Deferral
A participant may elect to defer a percentage of their salary or bonus up to 100%. The minimum salary deferral amount is $3,500. Pay deferred

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS DOCKET NO. G-04204A-06-0463 January 5,2007

under the plan is not included in W-2 earnings. Therefore, deferrals are not subject to federal or state income taxes at the time of deferral. However, deferred pay is subject to FICA and Medicare taxes in the year of deferral.

<u>401(k) Excess Company Match</u>
Limits on contributions to the TEP 401(k) Plan may keep highly compensated employees from receiving the full dollar-for-dollar Company match. If employees maximize their 401(k) deferral opportunity ($15,000 in 2006), the Company will contribute an amount to the Deferred Compensation Plan equal to the additional matching contribution that they would have received under the 401(k) Plan if their compensation in excess of the legal limitation ($220,000 in 2006) had been taken into account.

<u>Receiving Account Balance</u>
Full account balance will be distributed following retirement or termination. In the event of insolvency, plan participants will be general, unsecured creditors of the Company.

a.) and b.) See STF 5.72 (Retirement & Incentive Plan Expense). provided on the enclosed CD, for the cost of any SERP or similar programs and for the cost, by program, of each retirement program directly charged or allocated. The excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

RESPONDEST: Human Resources Services Group

WITNESS: Dallas Dukes

UNS Gas, Inc.
Retirement & Incentive Plan Expense-2005
For the year ended 12/31/05
In response to STF 5.72a and 5.72b

Plan	2005 Expense per UNSG G/L	
UES Plans:		
UES Pension Plan	$	774,997
UES 401K Plan	$	165,519
UES PEP Plan	$	133,834
Other Plans:		
SERP Plan	$	93,075
Long-Term Incentive Plan	$	108,920
PEP Plan	$	52,860
Deferred Comp Plan	$	11,315
Omnibus Plan	$	38,342
	$	1,378,862

**UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
January 18,2007**

STF 11.5 Incentive Compensation. Refer to the response to RUCO 6.10.

a. Show in detail the 2004 and 2005 PEP financial performance goals and the actual results.

b. Show in detail how the Special Recognition Award in 2005 was determined.

c. Provide the PEP in effect during each year, 2004, 2005 and 2006.

RESPONSE:

a. Please see STF 11.5(a), Bates Nos. UNSG(0463)05831 to UNSG(0463)05832, on the enclosed CD for the 2004 and 2005 UNS Gas, Inc. ("UNS Gas") portion of PEP which includes financial performance goals and actual results. STF 11.5(a) contains confidential information and is being provided pursuant to the terms of the Protective Agreement.

b. UNS Gas is in the process of gathering this information and will provide it shortly.

c. UNS Gas is in the process of gathering this information and will provide it shortly.

SUPPLEMENTAL RESPONSE:

a. UNS Gas' response to STF 11.5 (a) was provided to Staff on January 9, 2007.

b. As previously stated, the financial performance goal, which was a trigger under the PEP program for UNS Electric, UNS Gas and Tucson Electric Power Company ("TEP"), was not met. The financial performance was not met, in part, because of unplanned outages at the coal generating units which required TEP to purchase power on the open market. In discussions with the Board of Directors, the desire was to recognize employee achievements distinct from financial measures. The Board deemed it appropriate to implement a Special Recognition Award to employees for achievements in 2005. Normally, PEP is paid at 50% to 150% of target; the Special Recognition Award was paid at approximately 42% of the target for each of the three operating companies.

UNS GAS, INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S ELEVENTH SET OF DATA REQUESTS DOCKET NO. G-04204A-06-0463 January 18,2007

c. In 2004, the UniSource Energy Services, Inc. ("UES") PEP goal was separate from that of TEP. It had two primary goals: a financial goal specific to UES (UNS Gas and UNS Electric combined) and a set of goals measuring UNS Gas expense management, customer service, system reliability, and safety. Each of the two primary goals was weighted equally; however, PEP only paid if the primary financial goal was met. The primary UES financial goal was met in 2004.

In 2005, PEP had a similar structure as 2004 with two primary goals. However, the primary financial goal was now a combined financial measure for UNS Electric, UNS Gas and TEP. The second primary goal measured UNS Gas financial performance, customer and reliability goals, integration goals, and safety and employee goals. Similar to the prior year, each of the two primary goals was weighted equally and PEP only paid if the primary financial goal was met. As stated in response to STF 11.5 b, the 2005 primary financial goal was not met.

In 2006, the PEP structure was changed to the existing program today. It consists of three independent primary goals, and each of the primary goals has its own trigger, meaning that if one of the primary goals is not met, there is opportunity to still achieve on the two remaining primary goals. The three primary goals are comprised of a UniSource Energy Corporation Earnings per Shars goal (weighted 30%), a Cost Containment goal which manages Operations and Maintenance spending (weighted 30%), and Core Business and Customer Service goals (weighted 40%). The Core Business and Customer Service goals have many sub-goals beneath them, measuring reliability, customer service, project completion, regulatory and safety.

RESPONDENT: Michael Daranyi

WITNESS: Dallas Dukes

**UNS GAS, INC.'S RESPONSES TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 8,2006**

STF 5.91 Legal Expense. Please itemize the amount of non-rate case legal expense for the test year. For each distinct item over $20,000, show payee, amount, account, and indicate what services were performed and what the subject matter of the services was.

RESPONSE: STF 5.91, provided on the enclosed CD, is a worksheet in excel format which itemizes the amount of non-rate case legal expense for the test year. The Excel file is not identified by Bates numbers.

RESPONDENT: Regulatory Services Department

WITNESS: Dallas Dukes

UNS Gas, Inc.
Legal Invoice Query
2005

GL Date	Account	Amount	Payee/Vendor Name	Subject Matter	Service Performed
JAN-05	52010	18.00	ROSHKA DEWULF & PATTEN PLC		
JAN-05	52010	200.00	MARY L BONILLA		
JAN-05	52010	307.13	LEWIS AND ROCA LLP		
JAN-05	52010	600.00	THELEN REID & PRIEST LLP		
JAN-05	52010	6,248.77	FLEISCHMAN & WALSH LLP		
JAN-05	52010	19,216.41	LEWIS AND ROCA LLP		
MAR-05	52010	89.34	LEWIS AND ROCA LLP		
MAR-05	52010	252.00	ROSHKA DEWULF & PATTEN PLC		
MAR-05	52010	386.00	ROSHKA DEWULF & PATTEN PLC		
MAR-05	52010	563.40	ROSHKA DEWULF & PATTEN PLC		
MAR-05	52010	19,887.55	FLEISCHMAN & WALSH LLP		
APR-05	52010	111.35	LEWIS AND ROCA LLP		
APR-05	52010	180.00	ROSHKA DEWULF & PATTEN PLC		
APR-05	52010	11,201.01	ROSHKA DEWULF & PATTEN PLC		
APR-05	52010	19,083.78	FLEISCHMAN & WALSH LLP		
APR-05	52010	19,482.02	FLEISCHMAN & WALSH LLP		
MAY-05	52010	87,268.56	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
JUN-05	52010	(720.00)	THELEN REID & PRIEST LLP		
JUN-05	52010	133.75	LEWIS AND ROCA LLP		
JUN-05	52010	2,490.20	ROSHKA DEWULF & PATTEN PLC		
JUN-05	52010	11,030.00	FLEISCHMAN & WALSH LLP		
JUN-05	52010	11,234.83	ROSHKA DEWULF & PATTEN PLC		
JUL-05	52010	3.75	THELEN REID & PRIEST LLP		
JUL-05	52010	216.00	ROSHKA DEWULF & PATTEN PLC		
JUL-05	52010	360.00	ROSHKA DEWULF & PATTEN PLC		
JUL-05	52010	14,299.22	FLEISCHMAN & WALSH LLP		
AUG-05	52010	28,463.40	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
SEP-05	52010	40.80	LEWIS AND ROCA LLP		
SEP-05	52010	56,611.88	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
OCT-05	52010	297.80	ROSHKA DEWULF & PATTEN PLC		
OCT-05	52010	313.61	LEWIS AND ROCA LLP		
OCT-05	52010	462.00	BOULEY SCHLESINGER & SCHIPPERS		
OCT-05	52010	1,928.24	ROSHKA DEWULF & PATTEN PLC		
OCT-05	52010	2,304.50	ROSHKA DEWULF & PATTEN PLC		
OCT-05	52010	3,411.86	ROSHKA DEWULF & PATTEN PLC		
OCT-05	52010	32,330.68	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
NOV-05	52010	396.00	ROSHKA DEWULF & PATTEN PLC		
NOV-05	52010	15,277.45	ROSHKA DEWULF & PATTEN PLC		
NOV-05	52010	28,712.29	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
DEC-05	52010	17,612.56	ROSHKA DEWULF & PATTEN PLC		
DEC-05	52010	39,128.51	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
DEC-05	52010	139.20	LEWIS AND ROCA LLP		
DEC-05	52010	228.00	BOULEY SCHLESINGER & SCHIPPERS		
DEC-05	52010	1,662.40	ROSHKA DEWULF & PATTEN PLC		
DEC-05	52010	25,452.58	ROSHKA DEWULF & PATTEN PLC	Professional Research and filing services	Prudency Audit/PGA Surcharge/Broderick Complaint
DEC-05	52010	38,534.74	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case

517,451.57	Total legal expense
(311,050.06)	Rate case settlement negotiations
206,401.51	Difference

**UNS GAS, INC.'S RESPONSES TO
RUCO'S SIXTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 21,2006**

6.09 Pro Forma Adiustment – Worker's Compensation Expense – Please provide additional back-up information to explain why the Company is treating this expense in a similar manner as post employment benefits when worker's compensation is related to active employees only.

RESPONSE: The Worker's Compensation expense is recorded under Statement of Financial Accounting Standards No. 112, ***Employers' Accounting for Postemployment Benefits*** ("FAS 112"). FAS 112 specifically states that postemployment benefits are all types of benefits provided to former or inactive employees and worker's compensation is included as a postemployment benefit. Please see RUCO 6.09, Bates No. UNSG(0463)05610, on the enclosed CD for the summary portion of FAS 112 copied from the Financial Accounting Standards Board Original Pronouncements as Amended 200512006 Edition.

RESPONDENT: Ann Eckert

WITNESS: Dallas Dukes

Statement of Financial Accounting Standards No. 112
Employers' Accounting for Postemployment Benefits

an amendment of FASB Statements No. 5 and 43

STATUS

Issued: November 1992

Effective Date: For fiscal years beginning after December 15, 1993

Affects: Amends FAS 5, paragraph 7
Amends FAS 43, paragraph 1
Replaces FAS 43, paragraph 2
Amends FAS 107, paragraph 8(a)

Affected by: Paragraph 5(d) amended by FAS 123, paragraph 391 and FAS 123(R), paragraph D5
Paragraph 9 amended by FAS 123, paragraph 387; FAS 123(R), paragraph D5; and FAS 144, paragraph C8

AICPA Accounting Standards Executive Committee (AcSEC)

Related Pronouncement: SOP 94-6

Issues Discussed by FASB Emerging Issues Task Force (EITF)

Affects: No EITF Issues

Interpreted by: No EITF Issues

Related Issue: EITF Issue No. 96-5

SUMMARY

1. This Statement establishes accounting standards for employers who provide benefits to former or inactive employees after employment but before retirement (referred to in this Statement as *postemployment benefits*). Postemployment benefits are all types of benefits provided to former or inactive employees, their beneficiaries, and covered dependents. Those benefits include, but are not limited to, salary continuation, supplemental unemployment benefits, severance benefits, disability-related benefits (including workers' compensation), job training and counseling, and continuation of benefits such as health care benefits and life insurance coverage.

2. This Statement requires employers to recognize the obligation to provide postemployment benefits in accordance with FASB Statement No. 43, *Accounting for Compensated Absences*, if the obligation is attributable to employees' services already rendered, employees' rights to those benefits accumulate or vest, payment of the benefits is probable, and the amount of the benefits can be reasonably estimated. If those four conditions are not met, the employer should account for postemployment benefits when it is probable that a liability has been incurred and the amount can be reasonably estimated in accordance with FASB Statement No. 5, *Accounting for Contingencies*. If an obligation for postemployment benefits is not accrued in accordance with Statements 5 or 43 only because the amount cannot be reasonably estimated, the financial statements shall disclose that fact.

3. This Statement is effective for fiscal years beginning after December 15, 1993.

**UNS GAS, INC.'S RESPONSES TO
RUCO'S SIXTH SET OF DATA REQUESTS
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6.06 Pro Forma Adjustment – Worker's Compensation Expense – Please provide additional back-up information, which verifies the Commission's historical treatment of this specific expense is required to be recorded on a cash basis.

RESPONSE: UNS Gas does not have this additional back-up information.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

UNS GAS, INC.'S RESPONSE TO STAFF'S SIXTEENTH SET OF DATA REQUESTS Docket No. G-04202A-06-0463 January 22,2007

Subject: All information responses should ONLY be provided in searchable PDF, DOC or EXCEL files via email or electronic media.

STF 16.1 AGA Dues. Refer to the response to STF 5.62.

a. Please provide the invoices and all correspondence accompanying such invoices for the $41,854 in payments to the AGA mentioned in response to STF 5.62.

b. If different, please also provide the invoices and related correspondence for the total amount of AGA dues UNS Gas recorded during the test year, including an identification of any portions of AGA dues that UNS Gas recorded in below-the-line accounts.

c. Does UNS Gas participate in AGA's "Voluntary Ad Campaign?" If so, please identify all cost related to such participation, by amount and account, for the test year.

d. Does UNS Gas participate in or provide funding for any AGA advertising or marketing programs? If so, please identify all cost related to such participation, by amount and account, for the test year.

e. Please identify and provide the cost associated with all AGA advertisements used during the test year by UNS Gas.

f. Does UNS Gas agree that the NARUC sponsored audit reports on the expenditures of the American Gas Association provide the best information concerning AGA expenditures by category for use by utility regulatory commissions in evaluating which, if any, of the costs of that association should be included in utility rates? If not, please provide all information that UNS Gas believes is a better source for this purpose than the NARUC sponsored audit reports on the expenditures of the American Gas Association.

RESPONSE:

a. Please see STF 16.1 (a), Bates Nos. UNSG(0463)05908 to UNSG(0463)05910, on the enclosed CD for the supporting documentation for the $41,854 payment to AGA.

b. The $41,854 is the total amount paid to AGA during the test year.

**UNS GAS, INC.'S RESPONSE TO
STAFF'S SIXTEENTH SET OF DATA REQUESTS
Docket No. G-04202A-06-0463
January 22,2007**

c. UNS Gas did not participate in the AGA's "Voluntary Ad Campaign."

d. UNS Gas did not participate or provide funding for any AGA advertising or marketing programs.

e. UNS Gas had no cost associated with AGA advertisements.

f. UNS Gas has not reviewed the NARUC sponsored audit report of the AGA and presently has no opinion on the relevance of such a report.

RESPONDENT: Dallas Dukes

WITNESS: Dallas Dukes

UniSourceEnergy
SERVICES

FACSIMILE TRANSMITTAL SHEET

TO: Jessica Graham	FROM: Jennifer Wyraske
COMPANY: TEF	DATE: 1-31-05
FAX NUMBER: 520-571-4118	TOTAL NO. OF PAGES including COVER: 3
PHONE NUMBER: 520-745-3127	SENDER'S REFERENCE NUMBER:
RE:	YOUR REFERENCE NUMBER

☐ URGENT ☐ FOR REVIEW ☐ PLEASE COMMENT ☐ PLEASE REPLY ☐ PLEASE RECYCLE

NOTES/COMMENTS:

2901 W. SHAMRELL BOULEVARD, SUITE 110, FLAGSTAFF, ARIZONA 86001
PHONE: 928-226-2184 FAX: 928-779-5338

Voucher Request for Check, EFT or Wire Transfer

☐ Check ☐ EFT ☐ Wire Transfer

COMPANY SELECTION: (Check a box)

☐ Millennium Energy Holdings (MEHC)
☐ Millennium Environ Group (MEG)
☐ Tucson Electric Power (TEP)
☐ Other (specify) ______
☐ UniSource Energy Corporation (UNS)
☐ UNS Electric (UNE)
☒ UNS Gas (UNG)

VENDOR#: ______ **POW** ______

DUE DATE: ______ **INVOICE#:** ______ **AMOUNT:** $41854

PAY TO THE ORDER OF: American Gas Association

ADDRESS: PO Box 79226

CITY/STATE/ZIP: Baltimore Maryland 21279-0226

EXPLANATION/BUSINESS PURPOSE: Membership Dues

☐ Mail Check
☒ Return check to. Roxi Ashurst **Mail stop:** FLAG-G **Ext.** 2184

Requested by (Please Print): Jennifer Wytaske Signature: Jennifer Wytaske ______ Date 01-28-2005

For Immediate Pay On ... this voucher must be manually approved

Approved by (Please Print): G.A. Smith ______ Signature: G. A. Smith ______ Date 31 Jan 2005

FOR WIRE TRANSFERS ONLY: Vendor's bank routing information must be supported with a letter from the vendor or the bank routing information must be on the vendor's invoice.

Bank Name. ______

ABA (routing number) ______ Account ______

RECEIVED
JAN 31 2005
ACCOUNTS PAYABLE

MATERIALS >$ 2,500: need Procurement & Contracts Dept Approval.

Apvd. by (Please Print) ______ Signature: ______ Date ______

ACCOUNTING INFORMATION:

Project	Task	Expenditure Type	Expenditure Org (Cost Center)	Amount	
UNSG050	G500930	Member Dues - Corporate	UNSG Arizona Gas Admin	41854	00

Account Alias or G/L Account String - if applicable	Amount	

Note: Projects can not start with an X and Expenditure Types can not start with a 9. If you need accounting information, contact Amber Young in Financial Reporting at 745-3184. Amber will provide you with the information to put in the following box:

Form 5031 rev 12/04

AGA American Gas Association

Post Office Box 79226
Baltimore, Maryland 21279-0226
Telephone (202)824-7256
Fax (202)824-9156

UniSource Energy Corporation

2005 DUES

Year ending December 31, 2005

Full Member Company X   Limited Member Company ____

A.G.A. Dues Rules are attached. Dues are based upon the following operating income information ($000):

2001 ____* 2002 4,500 2003 4,128 Average ______

YOUR 2004 DUES WERE .... $ 20,927 1

YOUR 2005 DUES ARE .... $ 41,854 2

1. Dues phase-in amount. 2004 represents one-half of full does of $41,854.
2. Phase-in to full dues.

2005 Payment Schedule

______ Full amount enclosed   ______ Semi-annually (Jan.1, July 1)

______ Quarterly (Jan.1, Apr.1, July 1, Oct.1)   ______ Other (Please state)

Please return this completed form to the A.G.A. Treasurer at the above address. Payments may also be directed to *the* address noted above.

Invoice to: ....   Approved: ....

....   Title: ....

....   Date: ....

Phone: ( ) .... - ....   Fax ( ) .... - ....

IMPORTANT IRS REQUIRED NOTICE

Federal regulations require us to advise you that contributions or gifts to the American Gas Association are not deductible as charitable contributions for federal income tax purposes. Dues payments are usually deductible by members as an ordinary and necessary business expense. The American Gas Association expects that a portion of your dues may be used to influence legislation. **The Association will pay directly the federal tax that is due on lobbying activities.**

Dues include a one-year subscription to *American Gas*, the normal subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers.

**UNS GAS, INC.'S RESPONSES TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 8, 2006**

STF 5.28 For each plant account, please provide the actual cost of removal and net salvage information for each year, 2000 through 2005.

RESPONSE: The assets of UNS Gas were acquired from Citizens Communications Company ("Citizens") on August 11, 2003. Cost of removal and salvage data for periods prior to that date are not available. See STF 5.28, provided on the enclosed CD, for the accompanying schedule showing the actual annual cost of removal and salvage transactions recorded by FERC Account subsequent to that acquisition. The Excel file on the CD is not identified by Bates numbers.

Also, see the response to STF 5.6.

RESPONDENT: Carl Dabelstein

WITNESS: Karen Kissinger

UNS Gas, Inc.
Actual Cost of Removal and Proceeds of Sale

Plant Account	Description	Category	Year	Cost of Removal	Proceeds of Sale
	No Activity		2003	-	-
				-	-
	No Activity		2004	-	-
				-	-
376	Mains	01.376XX.051.00000.000	2005	160.00	-
376	Mains	01.376XX.053.00000.000	2005	3,375.10	
392	Transportation Equipment	01.392C1.051.00000.000	2005	-	10,607.00
392	Transportation Equipment	01.392C1.052.00000.000	2005	-	5,500.00
392	Transportation Equipment	01.392C1.053.00000.000	2005	-	1,601.50
392	Transportation Equipment	01.392C2.050.00000.000	2005	-	23,957.60
392	Transportation Equipment	01.392C2.051.00000.000	2005	-	54,948.86
392	Transportation Equipment	01.392C2.052.00000.000	2005	-	43,233.00
392	Transportation Equipment	01.392C2.053.00000.000	2005	-	1,500.00
392	Transportation Equipment	01.392C2.055.00000.000	2005	-	1,403.14
392	Transportation Equipment	01.392C2.056.00000.000	2005	-	36,124.00
392	Transportation Equipment	01.392C3.050.00000.000	2005	-	19,290.00
392	Transportation Equipment	01.392C3.051.00000.000	2005	-	8,400.00
392	Transportation Equipment	01.392C3.053.00000.000	2005	-	2,000.00
392	Transportation Equipment	01.392C3.056.00000.000	2005	-	3,113.16
392	Transportation Equipment	01.392C4.056.00000.000	2005	-	1,386.84
				3,535.10	213,065.10

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16, 2007

STF 13.2 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 6.B.2.b:

a. Please provide all cost studies and economic analysis that the Company has relating to its proposed increase in reimbursement from the customer to the Company for gas service line from $8 to $16 per foot.

b. Please provide all cost studies and economic analysis that the Company has relating to its proposed increase to $12 per foot for customers who provide the trench for the service line on their own property.

c. Please provide the complete documentation and calculations relied upon by the Company for its $16 per foot current costs (Smith, page 19, line 7-8) and $12 (Smith page 19, line 12).

d. Please identify for each year of UNS Gas ownership through 2006, the annual amount of customer reimbursement for gas service line connections, the annual cost incurred by UNS Gas for such connections, the amount of billings to customers for such connections, and the amount of feet installed.

RESPONSE:

a. Please see STF 13.2 on the enclosed CD for all cost studies and the economic analysis the Company has relating to its proposed increase in reimbursement from the customer to the Company for a gas service line from $8 to $16 per foot. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

b. Please see STF 13.2 on the enclosed CD for all cost studies and economic analysis that the Company has relating to its proposed increase to $12 per foot for customers who provide the trench for the service line on their own property. The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

c. Please see STF 13.2 on the enclosed CD for the complete documentation and calculations relied upon by the Company for its $16 per foot current costs (Smith, page 19, line 7-8) and $12 (Smith page 19, line 12). The Excel file on the enclosed CD is <u>not</u> identified by Bates numbers.

**ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
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d. Please see STF 13.2 on the enclosed CD for UNS Gas ownership through 2006, the annual amount of customer reimbursement for gas service line connections, the annual cost incurred by UNS Gas for such connections, the amount of billings to customers for such connections, and the amount of feet installed. The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Paula Smith

WITNESS: Gary Smith

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
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January 16, 2007

STF 13.6 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 6.B.2.b.

a. Please provide actual illustrative examples during 2006 for calculations prepared by the Company under the Incremental Contribution Study.

b. Please provide an illustrative example of calculations prepared pursuant to an Incremental Contribution Study, assuming the Company's proposed rates of reimbursement were to be approved.

RESPONSE:

a. Please see STF 13.6 on the enclosed CD for illustrative examples of calculations prepared by the Company under the Incremental Contribution Study during 2006. The Excel file on the enclosed CD is not identified by Bates numbers.

b. Please see STF 13.6 on the enclosed CD for an illustrative example of calculations prepared pursuant to an Incremental Contribution Study, assuming the Company's proposed rates of reimbursement were to be approved. The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Paula Smith

WITNESS: Gary Smith

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
Docket No. G-04202A-06-0463
January 16, 2007

STF 13.7 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 6.B.2.b.

a. Please identify the number of customers the Company anticipates would be affected by this proposed change and the total annual impact on such customers in total and on average.

b. Include supporting calculations for your response to part a.

RESPONSE:

a. Please STF 13.7 on the enclosed CD for the number of customers the Company anticipates would be affected by the proposed change and the total annual impact on such customers in total and on average. The Excel file on the enclosed CD is not identified by Bates numbers.

b. Please see STF 13.7 on the enclosed CD for supporting calculations. The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Paula Smith

WITNESS: Gary Smith

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
UNS GAS, INC.
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STF 13.8 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 10.C:

a. Referring to page 19, lines 20-21, please identify the specific provisions of the Arizona Administrative Code that the Company is relying upon for its alignment proposal.

b. For each change in "billing terms" proposed by the Company, please clearly identify the current provision, the basis for the current provision (e.g., cite to a prior Commission order) and explain clearly how and why the new or revised provision is an improvement over the existing provision.

RESPONSE:

a. R14-2-310(c) is the specific provision of the Arizona Administrative Code ("AAC") that UNS Gas is referring to for its alignment proposal.

b. UNS Gas' proposed revisions to the "Billing Terms" section of the Rules and Regulations are identified in the Direct Testimony of Gary A. Smith as Exhibit GAS - 2. The current Rules and Regulations were approved by the Commission in Decision No. 66028 with the acquisition of Citizens Communications Company. The proposed revisions align UNS Gas' "Billing Terms" with those outlined in the AAC, eliminating any confusion customers may have between them. Additionally, the proposed revisions will ultimately align with TEP and UNS Electric (both UniSource Energy Companies), thereby minimizing confusion among UNS Gas and UNS Electric customers who are often the same individuals.

RESPONDENT: Regulatory Services Department

WITNESS: Gary Smith

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTEENTH SET OF DATA REQUESTS TO
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Docket No. G-04202A-06-0463
January 16,2007

STF 13.9 Refer to the testimony of Gary A. Smith at page 19. Re the change to Section 10.C.

a. How do UNS Gas' proposed dues dates and time periods for late payment penalty charges compare with those currently in effect by other Arizona gas distribution utilities?

b. Please provide all comparative information the Company has with respect to how UNS Gas's proposed service line connection charges compare with those currently in effect by other Arizona gas distribution utilities.

c. How do UNS Gas' proposed dues dates and time periods for late payment penalty charges compare with those currently in effect by TEP and UNS Electric?

d. Please provide all comparative information the Company has with respect to how UNS Gas' proposed service line connection charges compare with those currently in effect by TEP and UNS Electric.

e. Please identify the annual amount of late payment penalty charge revenue for each year through 2006 under UNS Gas ownership.

f. Please identify the estimated annual impact on late penalty revenue if the Company's proposed time period for late penalty charges is implemented as proposed. Include supporting calculations showing in detail how such estimated annual impact was derived.

RESPONSE:

a. UNS Gas' proposed revisions to the due dates and time periods for late payment penalty charges were not made based on those of other Arizona gas distribution utilities, they were revised to follow the AAC R13-2-310. UNS Gas does not have the requested comparative information in its possession.

b. UNS Gas did not use comparative information when it determined and proposed its new Line Extension Tariff. UNS Gas does not have the requested comparative information in its possession.

c. TEP's current due date and time periods for late payment penalty charges are the same as those proposed by UNS Gas. Proposed

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revisions to UNS Electric's Rules and Regulations were filed on December 15, 2006. The proposed UNS Electric revisions match those of UNS Gas and TEP. Although UNS Gas did not use this information, the requested comparative information is as follows: TEP makes overhead distribution line extensions at no cost to the customer up to five (500) feet. Extensions in excess of five hundred (500) feet are computed at a rate of five dollars ($5.00) per foot for each foot of single phase line extension or eight dollars ($8.00) per foot for each foot of three phase line extension in excess of the free extension length. UNS Electric will extend single phase overhead distribution facilities without charge to customers provided that the length of the extension does not exceed four hundred (400) feet. Extensions in excess of four hundred (100) feet are provided based on an economic feasibility study and that such extension does not exceed a total construction cost of $25,000.

d. UNS Gas did not use comparative information from other Arizona Utilities with respect to its proposed revisions to the service line connection charge.

e. UNS Gas late payment revenue charged to FERC 487 was as follows:

2003 = $79,699
2004 = $381,781
2005 = $398,966
2006 = $524,050

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f. The Company is not able to estimate the impact the proposed change in time period may have on late payment revenue collections.

RESPONDENTS: Regulatory Services Department (a, b, c and d)
Amy Teller (e)
Jean Dannen (f)

WITNESS: Gary Smith

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STF 13.10 Refer to Section 10.J, Electronic Billing.

a. How does UNS Gas' proposed provision for electronic billing compare with provisions of other regulated Arizona utilities concerning electronic billing? Please provide all comparative information the Company has with respect to how UNS Gas' proposed provision for electronic billing compares with those of other Arizona utilities.

b. Does TEP or UNS Electric currently have a provision for electronic billing? If so, please provide a copy of those provisions.

c. If TEP or UNS Electric currently has a provision for electronic billing, please identify the number of customers, by year. that utilize electronic billing, through 2006.

d. Does UNS Gas anticipate any savings (e.g., postage, bill printing, etc.) from electronic billing? If so, please identify, quantify and explain the annual savings anticipated from electronic billing.

RESPONSE:

a. UNS Gas' proposed provision for electronic billing was based on TEP's electronic billing program. The new electronic billing program will have the same program capabilities once UNS Gas converts to its new customer information system. The Company did not make comparisons with other regulated Arizona utilities concerning electronic billing.

b. TEP e-bill began in May of 2003. UNS Electric launched e-bill in January 2006. For both Companies, customers can sign up for e-bill via telephone or the company web site. Customers are notified via email that their bill is ready to view.

c. TEP customers utilizing e-bill:

December 2003 - 13,879 customers
December 2004 - 33,120 customers
December 2005 - 50,383 customers
December 2006 - 67,765 customers

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UNS Electric customers utilizing e-bill:

December 2006 -1,773 customers

d. The Company estimates that during the test year it realized savings in postage, bill stock, mailing envelopes and remittance envelopes of approximately $4,000.

RESPONDENT: Regulatory Services Department (a)
Jean Dannen (b, c and d)

WITNESS: Gary Smith

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STF 13.11 Refer to Gary Smith's testimony at page 20 and Section 11.E.

a. Please identify the specific provisions of the Arizona Administrative Code that the Company is relying upon for its alignment proposal.

b. How many termination notices has UNS Gas issued to customers in each year through 2006 under its ownership of the gas system?

c. How many terminations has UNS Gas conducted in each year through 2006?

d. Does the Company have any studies or information concerning whether cutting the termination notice from 10 days to 5 days would present a hardship for customers? If so, please identify, explain and provide all such information.

e. Concerning the provision in 11.E.2:

i. From what location(s) does UNS Gas mail its termination notices?

ii. What is the approximate average time for delivery of first class mail to customers when mailed from the location(s) identified in response to the above request?

f. Please clarify whether the 10 days current provision and the 5 days proposed provision for termination notice in 11.E.1 are calendar days or business days.

g. Do any other Arizona utilities have a termination notice period less than 10 days? If so, please identify them.

h. Please identify the utility service termination notice period for each Arizona utility of which UNS Gas is aware.

RESPONSE:

a. R14-2-311 (E)(1) is the specific provision of the AAC that the Company is referring to for its alignment proposal.

b. Following are the number of Suspension of Gas Service Notices mailed to customers:

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28, 631 from August 11,2003 through December 31,2003

108,639 for Calendar year 2004 (Moratorium on mailing notices March 13, 2004 though April 18,2004)

106,407 for Calendar year 2005 (Moratorium on mailing notices November 21,2005 through December 31,2005)

101,382 for Calendar year 2006 (Moratorium on mailing notices January 1,2006 through March 31,2006)

c. Following are the number of terminations UNS Gas conducted:

1,281 from August 11,2003 through December 31,2003

3,942 for calendar year 2004 (Moratorium on disconnects from February 19,2004 through April 29,2004)

4,495 for calendar year 2005 (Moratorium on disconnects from December 1,2005 through December 31,2005)

3,445 for calendar year 2006 (Moratorium on disconnects from January 1, 2006 through March 31,2006)

d. The Company does not have study information. The five days provision is based on A.A.C. R14-2-311(E)(1). UNS Gas assumes that the Commission would not adopt a rule that would result in undue hardship for customers.

e. Concerning the provision in 11.E.2:

i. With the conversion to the new customer care and billing system (currently scheduled for April 2, 2007), notices will be mailed from Tucson Arizona.

ii. Approximate average time for delivery of first class mail is 2 days

f. The current ten-day provision is calendar days and the five-day proposed revision will be calendar days. The five-day provision in

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the Arizona Administrative Code (A.A.C. R14-2-311 (E)(1)) is also five calendar days. See A.A.C. R14-3-301(16).

g. TEP and UNS Electric currently match the AAC's five (5) day advance notice provision. The Company did not compare its proposed revision to any other Arizona Utilities.

h. Please see the response to STF 13.11 (g) above.

RESPONDENT: Regulatory Services Department (a, g and h)

WITNESS: Gary Smith

UNS GAS, INC.'S RESPONSES TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
SEPTEMBER 11,'2006

1.10 Rate Filing Please provide an electronic copy of the rate filing schedules A-H and all supporting workpapers, with all formulas intact.

RESPONSE: Electronic copies of the rate filing Schedules A-H and all supporting workpapers are provided on the attached CD as RUCO 1.10.

RESPONDENT: Janet Zaidenberg-Schrum

WITNESSES: Karen Kissinger and Dallas Dukes

UNS GAS
Cash Working Capital - LeadlLag Study
For the Test Year Endlng 12131105

Descrption	FERC	Pro Forma Test Year Amount		Revenue Lag Days		Lxpense Lag Days		Net Lag Days (Col. C - Col. D)	Lead/Lag Factor (Col. E/365)	Cash Working Capital Required (Col. F X Col.B)
(A)		(B)		(C)		(D)		(E)	(F)	(G)
Operating Expenses:										
Non-Cash Expenses -										
Bad Debts Expense	904	$ 722,634	1a							$
Depreciation	403/404	7,950,183	1.4a							
Amortization	406	(729,791)	1.4b							
Deferred Income Taxes		3,178,719								
Other Operating Expenses -										
Salaries and Wages (UNSG Direct Employees)	Multi	7,287,745	2a	38.95	C.	24.50	E.	14.45	0.0396	288,595
Incentive Pay (UNSG Direct Employees)	Multi	257,895	3a	38.95	C.	267.00	F.	(228.05)	(0.6248)	(161,133)
Purchased Gas	Calc	78,101,248	4a	38.95	C.	30.97	D.	7.98	0.0219	1,711,508
Office Supplies and Expenses	921	1,365,974	1.2a	38.95	C.	20.72	H.	18.23	0.0499	68,162
Injuries and Damages	925	574,128	1.2b	38.95	C.	64.75	H.	(25.80)	(0.0707)	(40,591)
Pensions and Benefits	926	2,452,071	1.2c	38.95	C.	54.66	H.	(15.71)	(0.0430)	(105,439)
Support Services - TEP (Direct Labor, Burdens, System Alloc.)	Note A.	4,570,692	6a	38.95	C.	44.91	G.	(5.96)	(0.0163)	(74,502)
Property Taxes	408	4,103,376	1.4c	38.95	C.	213.00	I.	(174.05)	(0.4768)	(1,956,490)
Payroll Taxes	408	537,877	1.4d	38.95	C.	19.30	I.	19.65	0.0538	28,938
Current Income Taxes		(1,203,222)		38.95	C.	41.42	I.	(2.47)	(0.0068)	8,182
Interest on Customer Deposits	431	170,459	1.4e	38.95	C.	182.50	J.	(143.55)	(0.3933)	(67,042)
Other Operations and Maintenance	Multi	7,501,807	X.	38.95	C.	53.10	K.	(14.15)	(0.0388)	(291,070)
Total Operating Expenses		116,841,794								
Other Cash Working Capital Elements:										
Interest on Long-Term Debt		5,334,825		38.95	C.	91.62	J.	(52.67)	(0.1443)	(769,815)
Revenue Taxes and Assessments	Calc	$ 18,788,535	L.	38.95	C.	76.25	I.	(37.30)	(0.1022)	(1,920,188)
Total Cash Working Capital										$ (3,280,886)

ProForma Operating Expenses - Excluding Income Taxes	$ 36,765,050	1.4f
Purchased Gas LeadlLag Only	78,101,248	4a
ProForma Oper. Exp. To Tie Too - Excl Income Taxes	114,866,298	
Less: 1a, 1.4a, 1.4b, 2a, 3a, 4a, 1.2a, 1.2b, 1.2c, 6a, 1.4c, 1.4d, 1.4e	107,364,490	
Other O&M	$ 7,501,807	X.

**UNS GAS, INC.'S RESPONSES TO
STAFF'S FIFTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
December 8,2006**

STF 5.36 Refer to Schedule E-1. Please provide the detailed components of the Accumulated Deferred Income Taxes amounts under Regulatory and Other Assets and under Deferred Credits and Other Liabilities, as of 12/31/05 and 12131/04.

RESPONSE: The ADIT appearing on Schedule E-1 is reported in accordance with Statement of Financial Accounting Standards No. 109 and reflects the tax effect of <u>all recorded</u> book-tax temporary differences, both operating and non-operating, that will reverse in the future. The net balances of $9.2 million and $6.1 million for December 31, 2005 and December 31, 2004, respectively, reflect future income tax liabilities that will come due when the differences reverse over time. See STF 5.36 on the enclosed CD for a summary of the components of the recorded balances. The Excel file on the CD is <u>not</u> identified by Bates numbers.

RESPONDENT: Carl W. Dabelstein

WITNESS: Karen Kissinger

Response to Staff D.R. 5.36
Per Books A.D.I.T. at 12/31/05

Timing Difference Description	A.D.I.T. at 12/31/05 Dr (Cr)	A.D.I.T. at 12/31/04 Dr (Cr)
Acct. 190 - Deferred Tax Assets		
Bad Debts Expense	132,013	174,332
Incentive Comp. - PEP	27,840	170,779
Interest Expense - Audit	10,950	-
Vacation Accrual - Book	94,651	32,260
Customer Advances in Aid of Construction	2,930,929	1,430,875
Dividend Equivalents	31,324	8,754
FAS 112 - Book	26,876	40,433
Long Term Incentive Comp.	100,975	91,838
Restricted Stock - Directors	20,121	15,828
Supplemental Executive Retirement Plan	88,747	-
Contributions in Aid of Construction	1,420,670	736,832
AMT - Credit	(189,102)	-
Pension Adjustment	-	19,799
Total Deferred Tax Assets	4,695,994	2,721,730
Acct. 282 A.D.I.T.		
Capitalized A&G	(343,587)	(29,994)
AFDC - Equity	(79,479)	(19,051)
Depreciation	(9,944,995)	(6,480,187)
Capitalized Repairs	(255,053)	
Acquisition Adjustment	(212,729)	
	(10,835,843)	(6,529,232)
Acct. 283 A.D.I.T.		
Purchased Gas Bank	(2,336,159)	(737,464)
Capiralized A&G	(443,036)	(1,289,636)
AFDC-Equity	(97,974)	(83,667)
CARES Program Expenses	(43,219)	-
Pensions Liability	(154,911)	(126,514)
Repairs Capitalized	(77,553)	(63,518)
	(3,152,852)	(2,300,799)
Total Deferred Tax Liabilities	(13,988,695)	(8,830,031)
Net Deferred Tax Liability	(9,292,701)	(6,108,301)

**UNS GAS, INC.'S RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
January 9,2007**

STF 11.10 Please provide the number of customers, by rate class, by month, for the test year and for months subsequent to the test year.

RESPONSE: For the number of customers, by rate class, by month, for the test year and for months subsequent to the test year, please see STF 11.10 provided on the enclosed CD. The Excel file on the CD is not identified by Bates numbers.

RESPONDENT: Brenda Pries

WITNESS: Tobin Voge

UNS GAS INC TOTAL RETAIL CUSTOMERS

	JAN45	FEB-05	MAR 05	APR 05	MAY 05	JUN-05	JUL-05	AUG-05	SEP-05	OCT-05	NOV-05	DEC-05
Retail Customers												
Residential:												
5751 Res RtR10	117,503	117,602	118,507	118,170	118,064	118,566	118,318	118,974	119,000	119,735	120,289	121,125
5752 Res CARES RtR12	4,798	4,905	5,045	5,161	5,295	5,358	5,407	5,443	5,377	5,341	5,484	5,556
5763 Compred Nat Gar RtCNG1			1	1	1	1	1	1	1	1	1	1
Total Residential Customers	122,301	122,507	123,553	123,332	123,360	123,925	123,726	124,418	124,378	125,077	125774	126,682
Commercial												
5753 Sm Vol Com Svc RtC20	10,877	10,891	10,974	10,960	10,902	10,816	10,772	10,730	10,701	10,728	10,821	11,017
5754 Lrg Vol Com Svc RtC22	10	10	10	10	10	10	10	10	10	11	11	11
5755 Irrigation Svc RtR60	6	6	6	6	6	6	6	6	6	6	6	6
5763 Compred Nat Gar RtCNG1	0		0									
Total Commercial Customers	10,893	10,907	10,990	10,976	10,918	10,832	10,788	10,746	10,717	10,745	10,838	11,034
Industrial:												
5758 Sm Vol Ind Svc RtI30	13	13	13	13	12	13	12	13	13	13	12	12
5759 Lrg Vol Ind Svc RtI32	7	7	7	7	7	7	7	7	7	7	7	7
Total Industrial Customers	20	20	20	20	19	20	19	20	20	20	19	19
Public Streets & Highway Lighting:												
5764 Special Gas Light Svc RtP	3	3	3	3	3	3	3	3	3	3	3	3
Public Streets & Highway Lighting	3	3	3	3	3	3	3	3	3	3	3	3
Other Sales - **Public Authorities:**												
5763 Compred Nat Gas RtCNG1	5	5	4	4	4	4	4	4	4	4	4	3
5765 Sm Vol Pub Athh Svc RtPA4	1,027	1,033	1,039	1,044	1,044	1,043	1,041	1,046	1,042	1,039	1,050	1,051
5766 Lrg Vol Pub Athh SK RtPA	6	6	6	6	6	6	6	6	6	6	5	5
Other Sales - Public Authorities	1,038	1,044	1,049	1,054	1,054	1,053	1,051	1,056	1,052	1,049	1,059	1,059
T1 Transportation												
Transportation Commercial	9	9	9	9	9	9	9	9	9	9	9	9
Transportation Industrial	10	10	10	10	10	10	10	10	10	10	10	10
Transporation Public Authority	3	3	3	3	3	3	3	3	3	3	3	3
	22	22	22	22	22	22	22	22	22	22	22	22
T2 Transportation												
Transportation Industrial	1	1	1	1	1	1	1	1	1	1	1	1
NSP **Customers**												
Commercial	6	6	6	6	6	6	6	6	6	6	6	6
Industrial	6	6	6	6	6	6	6	6	6	6	6	6
Public Authority	2	1	1	2	2	2	2	2	2	2	2	1
	14	13	13	14	14	14	14	14	14	14	14	13
TOTAL RETAIL CUSTOMERS	134,292	131,517	135,651	135422	135,391	135,870	135,624	136280	136,207	136,931	137730	138,833

	Jan-06	Feb 06	Mar-06	Apr-06	May06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06
Retail Customers											
Residential:											
5751 Res RtR10	122,128	122,416	123,191	123,342	123822	124,143	123,746	124,723	124,379	124,924	125,893
5752 Res CARES RtR12	5,670	5,754	5,930	5,994	5,929	5,845	5,789	5,736	5,811	5942	6,010
5763 Compred Nat Gar RtCNG1	1	1	1	1	1	1	1	2	2	2	2
Total Residential Customers	127,799	128171	129,128	129337	129,752	129,989	129,536	130,461	130,192	130,868	131,935
Commercial											
5753 Sm Vol Com Svc RtC20	11,149	11,161	11,234	11,228	11,226	11,097	11,037	11,051	11,026	11,125	11,283
5754 Lrg Vol Com Svc RtC22	11	11	11	11	11	11	11	10	11	11	11
5755 Irrigation Svc RtR60	6	6	5	5	5	5	5	5	5	5	5
5763 Compred Nat Gar RtCNG1				1	1			1			
Total Commercial Customers	11,166	11,178	11,250	11,245	11,243	11,113	11,053	11,067	11,042	11,141	11,299
Industrial:											
5758 Sm Vol Ind Svc RtI30	12	11	12	13	13	13	13	13	13	13	12
5759 Lrg Vol Ind Svc RtI32	7	7	7	6	7	7	7	7	7	7	7
Total Industrial Customers	19	18	19	19	20	20	20	20	20	20	19
Public Streets & Highway Lighting:											
5764 Special Gas Light Svc RtP	3	3	3	3	3	3	3	3	3	3	3
Public Streets & Highway Lighting	3	3	3	3	3	3	3	3	3	3	3
Other Sales - **Public Authorities:**											
5763 Compred Nat Gas RtCNG1	4	4	4	4	4	4	4	5	7	7	7
5765 Sm Vol Pub Athh Svc RtPA4	1,059	1,056	1,063	1,064	1,060	1,053	1,053	1,051	1,053	1,054	1,058
5766 Lrg Vol Pub Athh SK RtPA	5	5	5	5	5	5	5	5	5	5	5
Other Sales - Public Authorities	1,068	1,065	1,072	1,073	1,069	1,062	1,062	1,061	1,065	1,066	1,070
T1 Transportation											
Transportation Commercial	9	9	9	8	8	8	8	8	8	9	9
Transportation Industrial	10	10	10	10	10	10	10	10	10	10	10
Transporation Public Authority	3	3	3	3	3	3	3	3	3	3	3
	22	22	22	21	21	21	21	21	21	22	22
T2 Transportation											
Transportation Industrial	1	1	1	1	1	1	1	1	1	1	1
NSP **Customers**											
Commercial	6	6	6	6	6	6	6	6	6	6	6
Industrial	6	6	6	6	6	6	6	6	6	6	6
Public Authority	1	1	1	1	1	1	1	1	1	1	1
	13	13	13	13	13	13	13	13	13	13	13
TOTAL RETAIL CUSTOMERS	140,091	140471	141,508	141,712	142,122	142,222	141,709	142,647	142,357	143,134	144,332

R14-2-102. Treatment of depreciation

A. The following definitions shall apply in this Section unless the context otherwise requires:
   1. "Accumulated depreciation" means the summation of the annual provision for depreciation from the time that the asset is first devoted to public service.
   2. "Cost of removal" means the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto.
   3. "Depreciation" means an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life.
   4. "Depreciation rate" means the percentage rate applied to the original cost of an asset to yield the annual provision for depreciation.
   5. "Net salvage" means the salvage value of property retired less the cost of removal.
   6. "Original cost" means the cost of property at the time it was first devoted to public service.
   7. "Property retired" means assets which have been removed, sold, abandoned, destroyed, or which for any cause have been withdrawn from service and books of account.
   8. "Salvage value" means the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; or if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts.
   9. "Service life" means the period between the date an asset is first devoted to public service and the date of its retirement from service.

B. All public service corporations shall maintain adequate accounts and records related to depreciation practices, subject to the following:
   1. Annual depreciation accruals shall be recorded.
   2. A separate reserve for each account or functional account shall be maintained.
   3. The cost of depreciable plant adjusted for net salvage shall be distributed in a rational and systemic manner over the estimated service life of such plant.
   4. Public service corporations having less than $250,000 in annual revenue shall not be required to maintain depreciation records by separate accounts but shall make annual composite accruals to accumulated depreciation for total depreciable plant.

C. Requests for depreciation rate changes and methods for estimating depreciation rates shall be as follows:
   1. If a public service corporation seeks a change in its depreciation rates, it shall submit a request for such as part of a rate application in accordance with the requirements of R14-2-103.
   2. A public service corporation may propose any reasonable method for estimating service lives, salvage values, and cost of removal. The method shall be fully described in a request to change depreciation rates.
   3. Data and analyses supporting the change shall be submitted, including engineering data and assessment of the impact and appropriateness of the change for ratemaking purposes.
   4. Changed depreciation rates shall not become effective until the Commission authorizes such changes.

D. Upon the motion of any party or upon its own motion, the Commission may determine that good cause exists for granting a waiver from one or more of the requirements of this Section.

Historical Note

Former Section R14-2-102 repealed, former Section R14-2-127 renumbered as Section R14-2-102 without change effective March 2, 1982 (Supp. 82-2). Forward to the rule corrected as filed April 13, 1973 (Supp. 89-1). Section R14-2-102 repealed, new Section adopted effective April 9, 1992 (Supp. 92-2).

BEFORE THE
ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

DIRECT TESTIMONY AND EXHIBIT
OF
DAVID C. PARCELL

ON BEHALF OF THE
COMMISSION STAFF

FEBRUARY 9, 2007

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BEFORE THE ARIZONA CORPORATION COMMISSION

DOCKET NO. G-04204A-06-0463

DIRECT TESTIMONY AND EXHIBIT

OF

DAVID C. PARCELL

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is David C. Parcell. I am Executive Vice President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. PLEASE SUMMARIZE YOUR EDUCATION BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In connection with this, I have previously filed testimony and/or testified in over 375 utility proceedings before about 35 regulatory agencies in the United States and Canada. Schedule 1 provides a more complete description of my education and relevant work experience.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?

A. Yes, I have testified in a number of prior Arizona Corporation Commission ("Commission") proceedings, including the recent electric rate case involving Arizona Public Service Company (Docket No. E-01345A-05-0816). That testimony was provided on behalf of the Commission Staff.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the Commission Staff to evaluate the cost of capital aspects of the current filing of UNS Gas, Inc. ("UNS Gas"). I have performed independent studies and am making recommendations of the current cost of capital for UNS Gas. In addition, because UNS Gas is a subsidiary of UniSource Energy Corporation ("UniSource Energy"), I also have evaluated this entity in my analyses.

Q. HAVE YOU PREPARED AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 14. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A. My overall cost of capital recommendations for UNS Gas are:

	Percent	Cost	Return
Long-Term Debt	55.33%	6.60%	3.65%
Common Equity	44.67%	9.50-10.50%	4.24-4.69%
Total	100.00%		7.89-8.34%
			8.12% mid-point

UNS Gas' application requests a return on common equity of 11.0 percent and overall rate of return of 8.80 percent.

Q. PLEASE SUMMARIZE YOUR COST OF CAPITAL ANALYSES AND RELATED CONCLUSIONS FOR UNS GAS.

A. This proceeding is concerned with UNS Gas' regulated natural gas distribution utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. UNS Gas' proposed capital structure is a hypothetical capital structure that employs 50 percent long-term debt and 50 percent common equity. I use the actual capital structure of UNS Gas as of December 31, 2005 in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of long-term debt. I have used the 6.60 percent cost rate for long-term debt contained in UNS Gas' application.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for UNS Gas. Each of these methodologies is applied to two groups: one of proxy gas utilities and one of a combination of gas and electric utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.25-10.5% (9.88% mid-point)
Capital Asset Pricing Model	9.5-10.25% (9.88% mid-point)
Comparable Earnings	10.0%

Based upon these findings, I conclude that the cost of common equity for UNS Gas is within a range of 9.5 percent to 10.5 percent (10 percent mid-point), which reflects each of the model results.

Using the results from these three steps, I have calculated a weighted cost of capital (overall rate of return) range of 7.89 percent to 8.34 percent (8.12 percent mid-point, which incorporates a cost of common equity of 10.0 percent). My specific cost of capital recommendation for UNS Gas is 8.12 percent.

III. <u>ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES</u>

Q. WHAT ARE THE PRIMARY ECONOMIC AND LEGAL PRINCIPLES THAT ESTABLISH THE STANDARDS FOR DETERMINING A FAIR RATE OF RETURN FOR A REGULATED UTILITY?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (<u>i.e.</u>, rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The revenue impact of the cost of capital is thus derived by multiplying the rate base by the rate of return and allowing a factor for income taxes.

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (<u>i.e.</u>, debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an <u>ex post</u> (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an <u>ex ante</u> (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably. I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments.

These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions are universally cited as providing the standards for a fair rate of return. The first is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A **public utility** is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. **[Emphasis added.]**

It is my understanding that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a **balancing** of the **investor** and **consumer interests** . . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity

> **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the enterprise, so as to **maintain its credit** and to **attract capital**. **[Emphasis added.]**

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In *Simms v. Round Valley Light & Power Company*,[1] the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> "In the Hope case the Court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at."

My testimony does not advocate that the Commission ignore the *Simms* holding in this regard, or the fair value of UNS Gas' property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the *Hope* and *Bluefield*

[1] 294 P.2d 378 (1956).

decisions to be helpful in their discussion of comparable earnings, financial integrity and capital attraction.

Q. HOW CAN THESE PARAMETERS BE EMPLOYED TO ESTIMATE THE COST OF CAPITAL FOR A UTILITY?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the component of the capital structure that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF THE COST OF COMMON EQUITY IN THIS PROCEEDING?

A. I have utilized three methodologies to determine UNS Gas' cost of common equity: the DCF, CAPM, and CE methods. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. WHY ARE ECONOMIC AND FINANCIAL CONDITIONS IMPORTANT IN DETERMINING THE COSTS OF CAPITAL?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), and the level of inflation. My understanding is that use of the factors is consistent with the Supreme Court's Bluefield decision, which noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. WHAT INDICATORS OF ECONOMIC AND FINANCIAL ACTIVITY HAVE YOU EVALUATED IN YOUR ANALYSES?

A. I have examined several sets of economic statistics for the period 1975 to present. I chose this period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to date, and thus makes it possible to assess changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and thus permits a comparison of structural (or long-term) trends.

Q. PLEASE DESCRIBE THE TIMEFRAME OF THE THREE PRIOR BUSINESS CYCLES AND THE MOST CURRENT CYCLE.

A. The three prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Present	

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS CONCERNING THE CHANGING TRENDS IN ECONOMIC CONDITIONS AND THEIR IMPACT ON COSTS OVER THIS BROAD PERIOD?

A. Yes, I do. As I will describe below, the U.S. economy has enjoyed general prosperity and stability over the period since the early 1980s. This period has been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs. The current business cycle began in late 2001, following a somewhat modest recession in 2001. During the recession and early in the succeeding expansion, the Federal Reserve lowered interest rates (i.e., Fed Funds rate) 11 times in 2001 and twice in 2003 in an effort to stimulate the economy.

Q. PLEASE DESCRIBE RECENT AND CURRENT ECONOMIC AND FINANCIAL CONDITIONS AND THEIR IMPACT ON THE COSTS OF CAPITAL.

A. Schedule 2 shows several sets of economic data. Page 1 contains general macroeconomic statistics while Pages 2 and 3 contain financial market statistics. Page 1 of Schedule 2 shows that the U.S. economy is currently in the fifth year of an economic expansion. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the unemployment rate. This current expansion has generally been characterized as slower growth, in comparison to prior expansions. This has resulted in lower inflationary pressures and interest rates.

The rate of inflation is also shown on Page 1 of Schedule 2. As is reflected in the Consumer Price Index (CPI), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 3.4 percent or lower. The 3.4 percent rate of inflation in 2005, which was similar to the level for 2004, was slightly higher than the most recent years, but was well below the levels of the past thirty years.

Q. WHAT HAVE BEEN THE TRENDS IN INTEREST RATES?

A. Page 2 of Schedule 2 shows several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates then fell substantially in conjunction with inflation rates throughout the remainder of the 1980s throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their lowest levels since the 1960s.

This low level of interest rates, in conjunction with the recent strength of the U.S. economy, may create an expectation that any near-term movement of interest rates will be upward. In fact, the Federal Reserve has, since the middle of 2004, increased short-term interest rates on 17 occasions, although each time by only 0.25 percent, in an attempt to insure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the economic recovery to date has not resulted in a pronounced increase in long-term rates. In fact, the current level of Fed Funds is about the same as the level in existence when the series of reductions began in 2000. Even if rates were to increase moderately, they would still remain well below historical levels.

Q. WHAT HAVE BEEN THE TRENDS IN COMMON SHARE PRICES?

A. Page 3 of Schedule 2 shows several series of common stock prices and ratios. These indicate that share prices were basically stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a significant upward trend in stock prices. During the initial years of the current expansion, however, stock prices were volatile and declined substantially from their highs reached in 1999 and early 2000. Share prices have increased somewhat since 2003 and currently stand at near record high levels.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS DISCUSSION OF ECONOMIC AND FINANCIAL CONDITIONS?

A. It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, even a moderate increase in interest rates, as well as other capital costs, would still result in capital costs that are low by historic standards. Therefore, it can reasonably be expected that cost of equity models, such as the DCF, currently produce returns that are lower than was the case in prior years.

V. UNS GAS' OPERATIONS AND RISKS

Q. PLEASE SUMMARIZE UNS GAS AND ITS OPERATIONS.

A. UNS Gas is a public utility that provides natural gas distribution services to some 140,000 customers in Arizona. UNS Gas was formerly the Arizona local gas distribution operations of Citizens Communications Company, prior to its 2003 acquisition by UniSource Energy. When UniSource Energy acquired the Arizona electric and gas assets from Citizens, it formed two operating companies - UNS Gas and UNS Electric.

Q. PLEASE DESCRIBE UNISOURCE ENERGY.

A. UniSource Energy is a holding company, whose principal subsidiary is Tucson Electric Power Company ("TEP"), a generation and distribution company that is the second-largest investor-owned utility in Arizona. UniSource Energy also owns UniSource Energy Services ("UES"), which contains UNS Gas and UNS Electric, both of which are distribution companies. It also owns Millennium Energy Holdings, the parent company of UniSource Energy's unregulated energy business whose principal subsidiary is Global Solar. UniSource Energy operates through four primary business segments – TEP, UNS Gas, UNS Electric, and Global Solar (the 2005 Annual Report of UniSource Energy indicated that the Company is in the process of exiting its Millennium Energy investments).

Q. WHAT HAVE BEEN THE BUSINESS SEGMENT RATIOS OF UNISOURCE ENERGY IN RECENT YEARS?

A. This is shown on Schedule 3. As this indicates, as of 2005, UNS Gas accounted for about 11 percent of the revenues of UniSource Energy and about 7 percent of total assets.

Q. WHAT ARE THE CURRENT BOND RATINGS OF UNISOURCE ENERGY AND TEP?

A. The current ratings of UniSource Energy and TEP are:

	Standard & Poor's	Moody's	Fitch
UniSource Energy Credit Ratings			
Senior Secured Debt	NR	Ba1	NR
Issuer Rating	NR	Ba1	N/A
Tucson Electric Power Credit Ratings			
Senior Secured Debt	BBB-	Baa2	BBB-
Senior Unsecured Debt	B+	Baa3	BB+
Issuer Rating	BB	Baa3	BB

Source: UniSource Energy Web Site.

UNS Gas does not have its own security ratings. The debt of UNS Gas is guaranteed by UES. As such, the debt of UNS Gas is related to the overall credit strength of UniSource Energy and TEP.

Q. DID THE ACQUISITION OF THE ASSETS CURRENT COMPRISING UNS GAS HAVE ANY IMPACT ON THE SECURITY RATINGS OF UNISOURCE ENERGY OR TEP?

A. No, it did not. Standard & Poor's, for example, made the following comments in an August 12, 2003 CreditWatch report on TEP:

> Standard & Poor's Ratings Services said today it affirmed its ratings on Tucson Electric Power Co. ('BB' corporate credit rating) and removed them from CreditWatch with negative implications. They were placed on CreditWatch Nov. 8, 2002, reflecting parent UniSource Energy Corp.'s announcement of an agreement to **purchase** the **Arizona electric** and gas **transmission and distribution assets** from Citizens Communications Co. The outlook is stable.
>
> The Aug. 11, 2003, acquisition of **these relatively low-risk, widely scattered regulated assets** for $220 million, **well below the book value** of about $425 million, **bolsters the consolidated business profile** of the UniSource Energy family of companies, and does so with a financing package that **marginally improves the overall financial condition of UniSource Energy**. These assets are subject to regulation by the Arizona Corporation Commission (ACC), as is Tucson Electric, and are structured as a wholly owned subsidiary of UniSource Energy called UniSource Energy Services.
>
> The addition of about 77,000 electric customers and 126,000 gas customers represents an increase of about 40% to Tucson Electric's customer base. The acquisition has received strong regulatory support,

> mainly because rate increases will be limited to only about one-half of what they would have been in the absence of the purchase, as well as because of operational challenges faced by prior management. **[Emphasis added]**

Q. UNS GAS IS PROPOSING A DECOUPLING MECHANISM. DOES THE POTENTIAL APPROVAL OF THIS REGULATORY MECHANISM AFFECT UNS GAS' RISK?

A. Yes, it does. Staff Witness Smith addresses UNS Gas' proposed mechanism in detail and generally concludes that the proposed regulatory mechanism is risk-reducing to the company as it transfers a portion of the risk from shareholders to ratepayers.

Q. HAS STANDARD & POOR'S COMMENTED GENERALLY ON THE POSITIVE ATTRIBUTES OF REGULATORY COST-RECOVERY MECHANISMS?

A. Yes, it has. In a 2006 Commentary Report, titled "Prolonged High Natural Gas Prices May Increase Credit Risk For U.S. Gas Distribution Companies," S&P made the following comments:

> ... in an environment of sustained elevated natural gas prices, will regulators continue to allow the LDCs the proper tools to capture costs and maintain credit quality? The answer to this question will be key in LDCs maintaining their credit quality as, historically, companies with stable recovery mechanisms have maintained strong ratings.
>
> . . .
>
> Regulatory Mechanisms
> Most LDCs operate in jurisdictions where regulators provide a purchased-gas adjustment clause, which reduces a significant portion of the risk associated with operating with volatile gas price costs.
>
> . . .
>
> Given today's high and volatile natural gas prices, maintaining strong credit quality depends on ratepayers bearing the responsibility for commodity costs. Automatic pass-through mechanisms linked to gas price indices provide the strongest level of support.

Several points are apparent from this report. First and significantly, pass-through mechanisms have the effect of transferring a portion of an LDC's risks from its stockholders to its ratepayers. Second, it is apparent that UNS Gas' proposed cost-recovery mechanism reduces risk by decoupling revenue from consumption. Third, the proposed additional regulatory mechanisms will have the effect, if approved, of further reducing UNS Gas' risk.

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE NEW REGULATORY MECHANISM THAT UNS GAS IS PROPOSING IN THIS PROCEEDING.

A. The decoupling mechanism is intended to insulate the Company from any variation in distribution revenues attributed to conservation, weather effects or price responses by the customer. This mechanism is especially risk-reducing.

Q. WHAT WILL BE THE EFFECT ON UNS GAS' PERCEIVED RISKS IF THESE REGULATORY MECHANISMS ARE ADOPTED?

A. The effect will be to transfer a significant portion of UNS Gas' business risks from its stockholders to its ratepayers.

Q. ARE YOU AWARE THAT UNS GAS IS REQUESTING THE INCLUSION OF CONSTRUCTION WORK IN PROCESS AS PART OF ITS RATE FILING?

A. Yes, I am. It is my understanding that UNS Gas is requesting some $7.2 million of Construction Work In Progress ("CWIP") in its request, which results in about $1.5 million of annual revenues to the Company. UNS Gas witness Grant cites the inclusion of CWIP as necessary for the Company to attract capital.

Q. DO YOU AGREE THAT IT IS NECESSARY FOR UNS GAS TO HAVE CWIP TREATMENT IN ORDER FOR IT TO ATTRACT CAPITAL?

A. No, I do not. It has been my general experience that CWIP treatment is generally regarded as a ratemaking practice to be used in situations where a utility has a very large construction program and the company requires the cash treatment in order to manage its construction program and related financing. As such, CWIP is not the norm, particularly for gas distribution companies.

In the case of UNS Gas, I do not believe that it is necessary to provide CWIP treatment in order for this Company to attract capital. As I indicated above, the rating agencies describe the operations of UNS Gas as low risk. It is further apparent that UNS Gas receives its financing based on the credit quality of UniSource Energy and/or UES, not based on the situation of the Company itself. In summary, I do not believe it is necessary for UNS Gas to receive CWIP treatment in order for it to attract capital.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. WHAT IS THE IMPORTANCE OF DETERMINING A PROPER CAPITAL STRUCTURE IN A REGULATORY FRAMEWORK?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the pool of dollars represented by the capital structure finance the rate base.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. HOW IS UNS GAS FINANCED?

A. UNS Gas is a subsidiary of UES, which in turn is a subsidiary of UniSource Energy. UNS Gas has two series of long-term notes outstanding, both of which are guaranteed by UES.

Q. HOW HAVE YOU EVALUATED THE CAPITAL STRUCTURE OF UNS GAS AND UNISOURCE ENERGY?

A. I have first examined the recent capital structure ratios of UNS Gas and UniSource Energy.

UNS Gas' capital structure did not exist until 2003, when UniSource Energy created a subsidiary from the local gas distribution assets in Arizona, as acquired from Citizens Communications. As is shown on Page 1 of Schedule 4, the common equity ratios of UNS Gas have been as follows:

	Including S-T Debt	Excluding S-T Debt
2003	34.7%	34.7%
2004	37.0%	37.0%
2005	44.4%	44.4%

This indicates a rising level of common equity over this period.

Q. WHAT ARE THE CAPITAL STRUCTURE RATIOS OF UNISOURCE ENERGY?

A. These are shown on Page 2 of Schedule 4. These common equity ratios of UniSource Energy, on a consolidated basis, are summarized below:

	Including S-T Debt	Excluding S-T Debt
2001	28.0%	28.0%
2002	28.8%	28.8%
2003	30.2%	30.2%
2004	31.6%	31.6%
2005	33.5%	33.6%

These common equity ratios are somewhat less than those of UNS Gas.

Q. HOW DO THE CAPITAL STRUCTURES OF UNS GAS COMPARE TO THE OTHER UTILITY SUBSIDIARIES OF UNISOURCE ENERGY?

A. This is shown on Page 3 of Schedule 4. As this indicates, UNS Gas and UNS Electric have higher common equity ratios than TEP and UniSource Energy.

Q. HOW DO THESE CAPITAL STRUCTURES COMPARE TO THOSE OF INVESTOR-OWNED ELECTRIC AND COMBINATION GAS/ELECTRIC UTILITIES?

A. Schedule 5 shows the common equity ratios (including short-term debt in capitalization) for the two groups of electric utilities covered by AUS Utility Reports. These are:

Year	Electric	Combination Gas And Electric
2001	42%	38%
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%

These common equity ratios are generally similar to those of UNS Gas in 2005.

Q. WHAT CAPITAL STRUCTURE RATIOS HAS UNS GAS REQUESTED IN THIS PROCEEDING?

A. The Company requests use of a hypothetical capital structure, comprised of 50 percent common equity and 50 percent long-term debt.

Q. DO YOU AGREE THAT THIS IS THE PROPER CAPITAL STRUCTURE TO USE FOR UNS GAS?

A. No, I do not. This capital structure contains a percentage of common equity that exceeds the historic levels of common equity employed by UNS Gas, as well as the other utility subsidiaries of UniSource Energy. It should be noted that use of a hypothetical structure, such as that proposed by UNS Gas, would have the effect, if adopted, of increasing the actual return on equity to a level exceeding that intentionally approved by the Commission. For example, if the cost of capital, including the capital structure, requested by UNS Gas were to be approved, the following cost of capital would be reflected in rates:

	Percent	Cost	Wgt. Cost
Debt	50%	6.6%	3.65%
Equity	50%	11.0%	5.15%
Totals			8.80%

It is apparent, however, that an awarded return of 8.8 percent would produce a higher actual return on equity, as shown below:

	Percent	Cost	Wgt. Cost
Debt	55.33%	6.6%	3.65%
Equity	44.67%	11.5%	5.15%
Totals			8.80%

This demonstrates that use of a hypothetical capital structure, as proposed by UNS Gas, would have the impact on increasing the actual return on equity by 50 basis points, or 0.50 percent.

Q. WHAT CAPITAL STRUCTURE DO YOU PROPOSE TO USE IN THIS PROCEEDING?

A. I propose use of the actual capital structure ratios of UNS Gas. This capital structure reflects the per books ratios of the Company.

Q. WHAT IS THE COST RATE OF LONG-TERM DEBT IN THE COMPANY'S APPLICATION?

A. The Company's filing cites a cost of long-term debt of 6.60 percent. I use this rate in my cost of capital analyses.

Q. CAN THE COST OF COMMON EQUITY BE DETERMINED WITH THE SAME DEGREE OF PRECISION AS THE COST OF DEBT?

A. No. The cost rate of debt is largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and CE - are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR UNS GAS?

A. UNS Gas is not a publicly-traded company. Consequently, it is not possible to directly apply cost of equity models to this entity. Its ultimate parent company, UniSource Energy, is publicly-traded. As a result, it is possible to conduct direct analyses of its cost of common equity, although this company's recent financial situation and diversified nature make its results of limited value. Consequently, it is necessary to analyze groups of comparison or "proxy" companies as a substitute for UNS Gas to determine its cost of common equity.

I have examined two such groups for comparison to UNS Gas. The first group of proxy companies I examined is a group of nine electric and combination gas electric companies, similar to UniSource Energy, selected based on the criteria shown on my Schedule 6. Second is the group of eleven natural gas utilities used by UNS Gas witness Grant in his cost of capital analyses.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DISCOUNTED CASH FLOW MODEL?

A. The discounted cash flow model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where: K = discount rate (cost of capital)
P = current price
D = current dividend rate
G = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF EQUATION?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is a dividend growth variant, which is expressed as follows:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (October-December 2006). The D_0 is the current annualized dividend rate for each proxy company.

Q. HOW HAVE YOU ESTIMATED THE DIVIDEND GROWTH COMPONENT OF THE DCF EQUATION?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock.

A wide array of indicators exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2001-2005 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS) (per Value Line);
3. 2006, 2007, and 2009-2011 projections of earnings retention growth (per Value Line);
4. 2003-2005 to 2009-2011 projections of EPS, DPS, and BVPS (per Value Line); and,
5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. PLEASE DESCRIBE YOUR INITIAL DCF CALCULATIONS.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and range of low/high values. These results can be summarized as follows:

	Mean	Median	High[2]
Comparison Group	8.3%	8.3%	10.5%
Grant Group	8.0%	7.4%	9.2%

[2] Using only the highest growth rate.

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

The DCF results in Schedule 7 indicate average (mean and median) DCF cost rates of about 7.5 percent to 8.5 percent. The highest DCF rates (i.e., using the highest growth rates only) are about 9.25 percent to 10.5 percent.

Q. WHAT DO YOU CONCLUDE FROM YOUR DCF ANALYSES?

A. Based upon my analyses, I believe a broad range of 9.25 percent to 10.5 percent represents the current DCF cost of equity for the proxy groups. This is approximated by the top DCF calculations for the groups examined in the previous analysis. I recommend a 9.25 percent to 10.5 percent (9.88 percent mid-point) for UNS Gas, which focuses on the upper portion of the DCF range.

I have focused on the upper portion of the DCF calculations since current financial conditions (low interest rates and high market-to-book ratios for utilities) have the effect of driving DCF results to low levels by historic standards.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF THE CAPITAL ASSET PRICING MODEL.

A. The Capital Asset Pricing Model ("CAPM") is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns.

Q. HOW IS THE CAPM DERIVED?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity

R_f = risk free rate

R_m = return on market

β = beta

R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple risk premium method does not, but rather the simple risk premium method assumes the same cost of equity for all companies exhibiting similar bond ratings.

Q. WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM YOUR CAPM ANALYSES?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE?

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three month average yield (October-December 2006) for 20-year U.S. Treasury bonds. Over this three month period, these bonds had an average yield of 4.84 percent.

Q. WHAT IS BETA AND WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1 are considered less risky than the market, whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas below 1. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM COMPONENT?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2005 (all available years reported by S&P). The average return on equity for the S&P 500 group over the 1978-2005 period is 14.09 percent. This Schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (i.e., risk premiums) between the S&P 500 and U.S.

Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.2 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2005 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.5%	4.9%

I conclude from this that the expected risk premium is about 5.9 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 9 shows my CAPM calculations using the risk premium. The results are:

	Mean	Median
Comparison Group	10.3%	10.3%
Grant Group	9.9%	9.6%

Q. WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF EQUITY?

A. The CAPM results collectively indicate a cost of about 9.5 percent to 10.25 percent for the two groups of comparison utilities.

X. COMPARABLE EARNINGS ANALYSIS

Q. PLEASE DESCRIBE THE BASIS OF THE CE METHODOLOGY.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle upon which regulation is based.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's original book value (reflected in the book common equity in its balance sheet) to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. HOW HAVE YOU EMPLOYED THE CE METHODOLOGY IN YOUR ANALYSIS OF UNS GAS' COMMON EQUITY COST?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100%) reflect a situation where a company is able to attract new equity capital without dilution of book value. As a result, maintenance of a stock price above book value is one measure of the fairness of a utility's authorized cost of equity.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my comparable earnings analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my comparable earnings analysis uses prospective returns and thus is not backward looking.

Q. WHAT TIME PERIODS HAVE YOU EXAMINED IN YOUR CE ANALYSIS?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2005 (i.e., last fourteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2001-2005 (the last five years - the average length of a business cycle) and 1992-2001 (the most recent complete business cycle).

Q. PLEASE DESCRIBE YOUR CE ANALYSIS.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

	Historic		Prospective
Group	ROE	M/B	ROE
Comaprison Group	10.7%	171-197%	10.0-11.2%
Grant Group	11.6-11.8%	178-181%	10.3-11.7%

These results indicate that historic returns of 10.7-11.8 percent have been adequate to produce market-to-book ratios of 171-197 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2006, 2007, and 2009-2011 are within a range of 10.0 percent to 11.7 percent for the utility groups. These relate to 2005 market-to-book ratios of 192 percent or higher.

Q. HAVE YOU ALSO REVIEWED EARNINGS OF UNREGULATED FIRMS?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past fourteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 12.2 to 14.7 percent with market-to-book ratios ranging from 299 to 341 percent.

Q. HOW CAN THE ABOVE INFORMATION BE USED TO ESTIMATE THE COST OF EQUITY FOR UNS GAS?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industries with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is slightly more risky than the utility proxy groups.

Q. WHAT RETURN ON EQUITY IS INDICATED BY THE CE ANALYSIS?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 10 percent. Recent returns of 10.7 to 11.8 percent have resulting in market-to-book ratios of 171 and greater.

Prospective returns of 10.0 to 11.7 percent have been accompanied by market-to-book ratios of over 197 percent. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 10 percent or less should thus result in a market-to-book ratio of at least 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

XI. RETURN ON EQUITY RECOMMENDATION

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR THREE COST OF EQUITY ANALYSES.

A. My three methodologies produce the following:

Discounted Cash Flow	9.25-10.5% (9.88% mid-point)
Capital Asset Pricing Model	9.5-10.25% (9.88% mid-point)
Comparable Earnings	10.0%

My overall conclusion from these results is an overall range of 9.25 percent to 10.5 percent, which focuses on the respective ranges of my individual model findings. Focusing on the respective mid-points, the range is 9.88 percent to 10.0 percent. I conclude that the cost of equity rate for UNS Gas is in the range from 9.5 percent to 10.5 percent (mid-point 10.0 percent).

XII. TOTAL COST OF CAPITAL

Q. WHAT IS THE TOTAL COST OF CAPITAL FOR UNS GAS?

A. Schedule 13 reflects the total cost of capital for the Company using the December 31, 2005 capital structure and cost of long-term debt, and my common equity cost recommendations. The resulting total cost of capital is a range of 7.89 percent to 8.34 percent, with a mid-point of 8.12 percent. I recommend that this 8.12 total cost of capital be established for UNS Gas.

Q. DOES YOUR COST OF CAPITAL RECOMMENDATION PROVIDE THE COMPANY WITH A SUFFICIENT LEVEL OF EARNINGS TO MAINTAIN ITS FINANCIAL INTEGRITY?

A. Yes, it does. Schedule 14 shows the pre-tax coverage that would result if UNS Gas earned the mid-point of my cost of capital recommendation. As the results indicate, the mid-point of my recommended range would produce a coverage level within the benchmark range for a BBB rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. HAVE YOU REVIEWED THE TESTIMONY AND COST OF CAPITAL RECOMMENDATION OF UNS GAS WITNESS KENTTON C. GRANT?

A. Yes, I have. Mr. Grant is recommending the following cost of capital for UNS Gas:

Capital Item	Percent	Cost	Weighted Cost
Long-term Debt	50.0%	6.60%	3.30%
Common Equity	50.0%	11.00%	5.50%
Total	100.0%		8.80%

Mr. Grant's 11.0 percent cost of common equity recommendation is derived as follows:

	Range	Median
DCF	9.1-10.5%	9.9%
CAPM	9.9-11.7%	11.0%

Q. DO YOU HAVE ANY COMMENTS CONCERNING MR. GRANT'S DCF ANALYSIS AND RECOMMENDATIONS?

A. I note that Mr. Grant's 9.1-10.5 percent DCF conclusions do not very significantly from my DCF conclusions of 9.25-10.5 percent. As a result, I have no further comments on his DCF analyses and conclusions at this time.

Q. WHAT ARE YOUR COMMENTS CONCERNING MR. GRANT'S CAPM ANALYSIS AND CONCLUSIONS?

A. Mr. Grant's CAPM analysis takes the following form:

Risk-free rate	=	5.3%	=	April, 2006 20-yr. T bonds
Risk Premium	=	5.3%	=	Ibbotson risk premium
Beta	=		=	Value Line

I have concerns with Mr. Grant's risk-free rate and his risk premium inputs. His 5.3 percent risk free rate is now out-dated. As I indicated in my CAPM analyses, the current (i.e., December, 2006) yield on 20-year Treasury bonds is 4.78 percent and the most recent three-month average (i.e., October-December, 2006) yield is 4.83 percent.

My disagreement with Mr. Grant's risk premium is his exclusive reliance on the 1926-2005 arithmetic average difference between large company stocks (i.e., S&P 500) and long-term Treasury bonds. As I indicated earlier in my testimony, it is preferable to use multiple sources of risk premium measures, as I have done.

Q. MR. GRANT ALSO MAKES AN ADJUSTMENT FOR THE SIZE OF UNS GAS. IS THIS PROPER?

A. No, it is not. UNS Gas does not raise its own equity capital (as it comes from UniSource Energy) and its debt is guaranteed by UES. As a result, it is these entities that are evaluated by investors and it is the size of these entities that investors consider. I note, in this regard, that UniSource Energy has some $1.3 billion market value of equity and Value Line describes this Company as a "Mid Cap" stock.

Q. MR. GRANT ALSO CITES THE GROWTH OF UNS GAS AS A RISK INDICATOR. DO YOU AGREE WITH THIS?

A. No, I do not. My earlier testimony cites a S&P analysis of UniSource Energy that describes the UNS Gas and UNS Energy components as "low-risk."

Q. DO YOU AGREE WITH MR. GRANT'S PROPOSED HYPOTHETICAL CAPITAL STRUCTURE?

A. No, I do not. As I indicated earlier, it is not proper to impute more equity to UNS Gas than it and/or its parent affiliate companies employ.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
EXECUTIVE VICE PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

1995-Present	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

<u>Financial Economics</u> -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies.

Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's

Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association,
Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

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ECONOMIC INDICATORS

YEAR	REAL GDP GROWTH	IND PROD GROWTH	UNEMP RATE	CPI	PPI
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.3%	4.9%	1.7%	-1.2%
1998	4.2%	5.8%	4.5%	1.6%	0.0%
1999	4.5%	4.5%	4.2%	2.7%	2.9%
2000	3.7%	4.3%	4.0%	3.4%	3.6%
2001	0.8%	-3.6%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	-0.3%	5.8%	2.4%	1.2%
2003	2.7%	0.0%	6.0%	1.9%	4.0%
2004	4.2%	4.2%	5.5%	3.3%	4.1%
2005					
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.7%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.7%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.2%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	3.6%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	4.3%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	4.0%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	3.3%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.8%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	3.3%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.8%	2.7%	5.0%	8.8%	14.0%
4th Qtr.					
2006					
1st Qtr.	5.6%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.6%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	1.6%	5.2%	4.7%	0.4%	-4.4%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

YEAR	PRIME RATE	US TREAS T BILLS 3 MONTH	US TREAS T BONDS 10 YEAR	UTILITY BONDS Aaa	UTILITY BONDS Aa	UTILITY BONDS A	UTILITY BONDS Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%		7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005							
2003							
Jan	4.25%	1.17%	4.05%		6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec					5.62%	5.81%	6.05%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	Nasdaq Composite	DJIA	S&P D/P	S&P E/P
			1975 - 1982 Cycle		
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
			1983 - 1991 Cycle		
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988			2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
			1992 - 2001 Cycle		
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
			Current Cycle		
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005					
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,224.14	2,149.20	10,544.06	1.83%	
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.88%
3rd Qtr.	1,288.40	2,141.97		1.91%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit___(DCP-1)
Schedule 3

UNISOURCE ENERGY
SEGMENT FINANCIAL INFORMATION
2003 - 2005
($millions)

Segment	Operating Revenue	Net Income	Total Assets
		2003	
Tucson Electric Power	$852 87.6%	$129 113.2%	$2,767 88.6%
UNS Gas 1/	$47 4.8%	$1 0.9%	$185 5.9%
UNS Electric 1/	$56 5.8%	$2 1.8%	$125 4.0%
Global Solar	$2 0.2%	-$7 -6.1%	$26 0.8%
UniSource Energy Consolidated	$973	$114	$3,123
		2004	
Tucson Electric Power	$889 76.0%	$46 100.0%	$2,742 86.3%
UNS Gas	$129 11.0%	$6 13.0%	$201 6.3%
UNS Electric	$144 12.3%	$4 8.7%	$135 4.3%
Global Solar	$5 0.4%	-$5 -10.9%	$20 0.6%
UniSource Energy Consolidated	$1,169	$46	$3,176
		2005	
Tucson Electric Power	$937 76.2%	$48 104.3%	$2,575 82.3%
UNS Gas	$138 11.2%	$5 10.9%	$233 7.5%
UNS Electric	$150 12.2%	$5 10.9%	$161 5.1%
Global Solar	$5 0.4%	-$7 -15.2%	$20 0.6%
UniSource Energy Consolidated	$1,230	$46	$3,127

1/ 2003 figures for UNS Gas and UNS Electric are for period August 11 through December 31.

Note: Totals may not add to 100.0% due to "All Others" and "Reconciling Adjustments."

Source: UniSource Energy Annual Report.

UNS GAS
CAPITAL STRUCTURE RATIOS
2003 - 2005
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2003	$53,085	$0	$100,000	$0
	34.7%	0.0%	65.3%	0.0%
	34.7%	0.0%	65.3%	
2004	$58,758	$0	$100,000	$0
	37.0%	0.0%	63.0%	0.0%
	37.0%	0.0%	63.0%	
2005	$79,804	$0	$100,000	$0
	44.4%	0.0%	55.6%	0.0%
	44.4%	0.0%	55.6%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to STF 7.4.

UNISOURCE ENERGY CONSOLIDATED
CAPITAL STRUCTURE RATIOS
2001 - 2005
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
2001	$441,133.0	$0.0	$1,133,228.0	$0.0
	28.0%	0.0%	72.0%	0.0%
	28.0%	0.0%	72.0%	
2002	$456,640.0	$0.0	$1,130,803.0	$0.0
	28.8%	0.0%	71.2%	0.0%
	28.8%	0.0%	71.2%	
2003	$556,472.0	$0.0	$1,288,062.0	$0.0
	30.2%	0.0%	69.8%	0.0%
	30.2%	0.0%	69.8%	
2004	$580,718.0	$0.0	$1,259,320.0	$0.0
	31.6%	0.0%	68.4%	0.0%
	31.6%	0.0%	68.4%	
2005	$616,741.0	$0.0	$1,217,420.0	$5,000.0
	33.5%	0.0%	66.2%	0.3%
	33.6%	0.0%	66.4%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to STF 7.4.

UNISOURCE ENERGY AND UTILITY SUBSIDIARIES
CAPITAL STRUCTURE RATIOS
December 31, 2005
($000)

YEAR	COMMON EQUITY	PREFERRED SECURITIES	LONG-TERM DEBT	SHORT-TERM DEBT
Unisource Energy	$616,741.0	$0.0	$1,217,420.0	$5,000.0
Consolidated	33.5%	0.0%	66.2%	0.3%
	33.6%	0.0%	66.4%	
Tucson Electric	$558,646.0	$0.0	$821,170.0	$0.0
Power Company	40.5%	0.0%	59.5%	0.0%
	40.5%	0.0%	59.5%	
UNS Electric	$49,868.0	$0.0	$60,000.0	$5.0
	45.4%	0.0%	54.6%	0.0%
	45.4%	0.0%	54.6%	
UNS GAS	$79,804.0	$0.0	$100,000.0	$0.0
	44.4%	0.0%	55.6%	0.0%
	44.4%	0.0%	55.6%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to STF 7.4.

Exhibit___(DCP-1)
Schedule 5

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2001	42%	38%
2002	38%	36%
2003	42%	38%
2004	47%	43%
2005	44%	47%

Note: Averages include short-term debt.

Source: AUS Utility Reports.

Exhibit___(DCP-1)
Schedule 6

COMPARISON COMPANIES
BASIS FOR SELECTION

Company	Market Cap (000)	Percent Revenues Electric	Common Equity Ratio	Value Line Safety	Moody's/ S&P Bond Rating	S&P Stock Ranking
Unisource Energy	$1,300,000	86%	25%	3	BBB- / Baa2	B
Comparison Group*						
Cleco	$1,300,000	96%	52%	3	BBB / Baa1	B+
DPL Inc	$3,100,000	100%	38%	3	BBB /	B+
Duquesne Light Holdings	$1,500,000	79%	37%	4	BBB+ / Baa1	B
Empire District	$675,000	93%	49%	3	BBB+ / Baa1	B
Hawaiian Electric	$2,300,000	83%	53%	2	BBB / Baa2	B+
Northeast Utilities	$3,500,000	71%	35%	3	BBB / Baa1	B
Pepco Holdings	$4,600,000	79%	42%	3	BBB+ / Baa1	B
PNM Resources	$2,000,000	78%	42%	2	BBB / Baa2	B+
Puget Energy	$2,800,000	61%	46%	3	BBB / Baa2	B

* Selected using following criteria:
Market cap of $500 million to $5 billion.
Electric Revenues of 40% or greater.
Common Equity Ratio of 35% or greater.
Value Line Safety of 1, 2 or 3.
S&P bond ratings of BBB and Moody's bond ratings of Baa.
S&P stock ranking of B or B+.

Sources: C.A. Turner Utility Reports, Standard & Poor's Stock Guide, Value Line Investment Survey.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	October-December, 2006 Stock Prices HIGH	LOW	AVERAGE	YIELD
Comparison Group					
Cleco	$0.90	$26.20	$24.78	$25.49	3.5%
DPL Inc	$1.00	$28.20	$27.00	$27.60	3.6%
Duquesne Light Holdings	$1.00	$20.28	$19.49	$19.89	5.0%
Empire District	$1.28	$25.10	$21.61	$23.36	5.5%
Hawaiian Electric	$1.24	$28.18	$26.50	$27.34	4.5%
Northeast Utilities	$0.75	$28.90	$23.26	$26.08	2.9%
Pepco Holdings	$1.04	$26.99	$24.25	$25.62	4.1%
PNM Resources	$0.88	$32.07	$27.47	$29.77	3.0%
Puget Energy	$1.00	$25.91	$22.72	$24.32	4.1%
Average	$1.01	$26.87	$24.12	$25.50	**4.0%**
Grant Comparable Gas Group					
AGL Resources	$1.48	$40.09	$36.04	$38.07	3.9%
Atmos Energy Corp	$1.28	$33.09	$28.40	$30.75	4.2%
Cascade Natural Gas	$0.96	$26.17	$25.40	$25.79	3.7%
Laclede Gas Company	$1.46	$37.51	$31.60	$34.56	4.2%
New Jersey Resources	$1.52	$53.16	$48.46	$50.81	3.0%
Nicor, Inc	$1.86	$49.92	$42.38	$46.15	4.0%
Northwest Natural Gas	$1.42	$43.69	$38.53	$41.11	3.5%
Piedmont Natural Gas	$0.96	$28.44	$24.95	$26.70	3.6%
South Jersey Industries	$0.98	$34.26	$29.10	$31.68	3.1%
Southwest Gas	$0.82	$39.37	$32.80	$36.09	2.3%
WGL Holdings	$1.35	$33.55	$31.16	$32.36	4.2%
Average	$1.28	$38.11	$33.53	$35.82	**3.6%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2001	2002	2003	2004	2005	Average	2006	2007	2009-2011	Average
Comparison Group										
Cleco	6.5%	5.6%	3.5%	3.9%	4.1%	4.7%	2.5%	3.0%	4.0%	3.2%
DPL Inc	13.7%	0.0%	2.2%	9.8%	0.8%	5.3%	8.0%	10.0%	6.5%	8.2%
Duquesne Light Holdings	0.0%	1.5%	2.5%	5.4%	4.5%	2.8%	0.0%	2.0%	4.5%	2.2%
Empire District	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	1.0%	3.0%	1.3%
Hawaiian Electric	4.4%	4.3%	3.9%	1.1%	1.5%	3.0%	1.5%	2.0%	3.5%	2.3%
Northeast Utilities	5.6%	3.2%	3.7%	1.6%	1.5%	3.1%	5.0%	4.0%	4.0%	4.3%
Pepco Holdings	12.6%	5.3%	2.0%	2.5%	2.4%	5.0%	1.5%	3.0%	5.0%	3.2%
PNM Resources	12.3%	3.1%	3.0%	4.5%	4.3%	5.4%	4.0%	4.0%	3.5%	3.8%
Puget Energy	0.0%	1.3%	2.1%	2.8%	2.9%	1.8%	2.0%	3.0%	3.5%	2.8%
Average	6.1%	2.7%	2.6%	3.5%	2.4%	**3.5%**	2.7%	3.6%	4.2%	**3.5%**
Grant Comparable Gas Group										
AGL Resources	4.2%	7.0%	6.6%	5.6%	6.2%	5.9%	5.5%	5.5%	5.0%	5.3%
Atmos Energy Corp	2.1%	1.9%	2.8%	1.7%	2.3%	2.2%	2.2%	3.0%	3.0%	2.7%
Cascade Natural Gas	4.6%	1.7%	0.0%	2.1%	0.0%	1.7%	1.0%	1.5%	4.5%	2.3%
Laclede Gas Company	1.8%	0.0%	3.1%	2.7%	3.1%	2.1%	2.1%	4.0%	3.5%	3.2%
New Jersey Resources	6.1%	6.9%	7.7%	7.8%	8.5%	7.4%	7.4%	8.0%	7.5%	7.6%
Nicor, Inc	7.9%	6.5%	1.5%	2.1%	2.3%	4.1%	4.5%	4.0%	3.5%	4.0%
Northwest Natural Gas	3.5%	1.9%	2.6%	2.7%	3.7%	2.9%	2.9%	3.7%	3.7%	3.4%
Piedmont Natural Gas	3.0%	1.7%	3.1%	3.7%	3.6%	3.0%	3.0%	3.5%	4.0%	3.5%
South Jersey Industries	3.5%	4.7%	5.0%	5.9%	6.2%	5.1%	5.1%	6.5%	6.5%	6.0%
Southwest Gas	1.9%	1.9%	1.7%	4.3%	2.2%	2.4%	2.4%	5.0%	6.0%	4.5%
WGL Holdings	3.8%	0.0%	6.2%	4.1%	4.6%	3.7%	3.7%	2.5%	3.0%	3.1%
Average	3.9%	3.1%	3.7%	3.9%	3.9%	**3.7%**	3.6%	4.3%	4.6%	**4.2%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '03-'05 to '09-'11 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Comparison Group								
Cleco	1.0%	2.0%	4.0%	2.3%	4.5%	2.0%	8.5%	5.0%
DPL Inc	-1.0%	0.5%	-1.0%	-0.5%	5.5%	3.5%	3.5%	4.2%
Duquesne Light Holdings	-12.0%	-8.5%	-14.5%	-11.7%	5.0%	0.0%	5.5%	3.5%
Empire District	-5.0%	0.0%	2.0%	-1.0%	9.5%	0.0%	2.5%	4.0%
Hawaiian Electric	1.0%	0.0%	3.0%	1.3%	3.0%	0.0%	2.5%	1.8%
Northeast Utilities	0.0%	30.5%	3.0%	11.2%	8.5%	6.5%	1.5%	5.5%
Pepco Holdings	-1.0%	0.0%	0.5%	-0.2%	8.0%	3.0%	3.0%	4.7%
PNM Resources	-1.0%	5.0%	4.5%	2.8%	6.0%	8.5%	5.5%	6.7%
Puget Energy	-7.5%	-11.5%	0.5%	-6.2%	5.0%	1.5%	4.0%	3.5%
Average	-2.8%	2.0%	0.2%	**-0.2%**	6.1%	2.8%	4.1%	**4.3%**
Grant Comparable Gas Group								
AGL Resources	13.5%	2.0%	8.5%	8.0%	4.5%	6.5%	6.0%	5.7%
Atmos Energy Corp	6.5%	2.0%	8.5%	5.7%	7.0%	2.0%	5.0%	4.7%
Cascade Natural Gas	3.5%	0.0%	??	1.8%	7.0%	0.5%	6.0%	4.5%
Laclede Gas Company	4.5%	0.5%	2.5%	2.5%	5.0%	2.0%	7.0%	4.7%
New Jersey Resources	8.5%	3.0%	7.0%	6.2%	4.5%	4.5%	6.5%	5.2%
Nicor, Inc	-3.5%	3.5%	1.5%	0.5%	4.0%	1.0%	4.5%	3.2%
Northwest Natural Gas	5.0%	1.0%	3.5%	3.2%	7.0%	4.0%	3.5%	4.8%
Piedmont Natural Gas	5.0%	5.0%	6.0%	5.3%	6.0%	5.5%	3.0%	4.8%
South Jersey Industries	11.5%	2.5%	13.0%	9.0%	7.0%	6.0%	6.0%	6.3%
Southwest Gas	-0.5%	0.0%	3.0%	0.8%	9.0%	0.0%	4.0%	4.3%
WGL Holdings	6.0%	1.5%	3.0%	3.5%	1.5%	2.0%	3.5%	2.3%
Average	5.5%	1.9%	5.7%	**4.2%**	5.7%	3.1%	5.0%	**4.6%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Comparison Group								
Cleco	3.6%	4.7%	3.2%	2.3%	5.0%	10.5%	5.1%	8.8%
DPL Inc	3.7%	5.3%	8.2%		4.2%	5.0%	5.7%	9.4%
Duquesne Light Holdings	5.1%	2.8%	2.2%		3.5%	n/a	2.8%	7.9%
Empire District	5.5%	0.0%	1.3%		4.0%	3.0%	2.1%	7.6%
Hawaiian Electric	4.6%	3.0%	2.3%	1.3%	1.8%	3.0%	2.3%	6.9%
Northeast Utilities	3.0%	3.1%	4.3%	11.2%	5.5%	12.0%	7.2%	10.2%
Pepco Holdings	4.1%	5.0%	3.2%		4.7%	4.0%	4.2%	8.3%
PNM Resources	3.0%	5.4%	3.8%	2.8%	6.7%	9.7%	5.7%	8.7%
Puget Energy	4.2%	1.8%	2.8%		3.5%	4.0%	3.0%	7.2%
Average	4.1%	3.5%	3.5%	4.4%	4.3%	6.4%	4.2%	**8.3%**
Median								**8.3%**
Composite		7.6%	7.6%	8.5%	8.4%	**10.5%**	8.3%	
Grant Comparable Gas Group								
AGL Resources	4.0%	5.9%	5.3%	8.0%	5.7%	n/a	6.2%	10.2%
Atmos Energy Corp	4.3%	2.2%	2.7%	5.7%	4.7%	6.1%	4.3%	8.5%
Cascade Natural Gas	3.8%	1.7%	2.3%	1.8%	4.5%	n/a	2.6%	6.3%
Laclede Gas Company	4.3%	2.1%	3.2%	2.5%	4.7%	n/a	3.1%	7.4%
New Jersey Resources	3.1%	7.4%	7.6%	6.2%	5.2%	5.0%	6.3%	9.4%
Nicor, Inc	4.1%	4.1%	4.0%	0.5%	3.2%	3.1%	3.0%	7.1%
Northwest Natural Gas	3.5%	2.9%	3.4%	3.2%	4.8%	5.0%	3.9%	7.4%
Piedmont Natural Gas	3.7%	3.0%	3.5%	5.3%	4.8%	4.0%	4.1%	7.8%
South Jersey Industries	3.2%	5.1%	6.0%	9.0%	6.3%	6.0%	6.5%	9.7%
Southwest Gas	2.3%	2.4%	4.5%	0.8%	4.3%	12.0%	4.8%	7.1%
WGL Holdings	4.2%	3.7%	3.1%	3.5%	2.3%	3.0%	3.1%	7.4%
Average	3.7%	3.7%	4.2%	4.2%	4.6%	5.5%	4.3%	**8.0%**
Median								**7.4%**
Composite		7.4%	7.8%	7.9%	8.3%	**9.2%**	8.0%	

Note: Negative values excluded.
Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 8

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.26%	5.11%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
Average			**14.09%**	**7.90%**	**6.19%**

Sources: Standard & Poor's Analysts' Handbook and Ibbotson Associates 2006 Yearbook.

Exhibit___(DCP-1)
Schedule 9

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	MARKET RETURN	CAPM RATES
Comparison Group				
Cleco	4.83%	1.25	5.90%	12.2%
DPL Inc	4.83%	0.95	5.90%	10.4%
Duquesne Light Holdings	4.83%	1.00	5.90%	10.7%
Empire District	4.83%	0.80	5.90%	9.6%
Hawaiian Electric	4.83%	0.70	5.90%	9.0%
Northeast Utilities	4.83%	0.90	5.90%	10.1%
Pepco Holdings	4.83%	0.90	5.90%	10.1%
PNM Resources	4.83%	1.00	5.90%	10.7%
Puget Energy	4.83%	0.80	5.90%	9.6%
Average	4.83%	0.92	5.90%	**10.3%**
Median				**10.3%**
Grant Comparable Gas Group				
AGL Resources	4.83%	0.95	5.90%	10.4%
Atmos Energy Corp	4.83%	0.80	5.90%	9.6%
Cascade Natural Gas	4.83%	0.80	5.90%	9.6%
Laclede Gas Company	4.83%	0.90	5.90%	10.1%
New Jersey Resources	4.83%	0.80	5.90%	9.6%
Nicor, Inc	4.83%	1.30	5.90%	12.5%
Northwest Natural Gas	4.83%	0.75	5.90%	9.3%
Piedmont Natural Gas	4.83%	0.80	5.90%	9.6%
South Jersey Industries	4.83%	0.70	5.90%	9.0%
Southwest Gas	4.83%	0.85	5.90%	9.8%
WGL Holdings	4.83%	0.85	5.90%	9.8%
Average	4.83%	0.86	5.90%	**9.9%**
Median				**9.6%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average	2006	2007	2009-11
Comparison Group																			
Cleco	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	13.5%	12.8%	8.0%	8.5%	9.5%
DPL Inc	13.3%	14.5%	15.1%	15.2%	15.5%	15.4%	14.9%	15.2%	18.6%	25.4%	22.6%	16.1%	23.5%	12.6%	16.3%	20.0%	26.5%	26.0%	18.5%
Duquesne Light Holdings	12.4%	12.0%	12.5%	13.2%	13.2%	12.9%	13.1%	14.0%	8.0%	2.7%	16.2%	15.0%	15.6%	14.1%	11.4%	12.7%	6.0%	13.0%	13.5%
Empire District	10.3%	9.4%	10.6%	9.4%	9.4%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	6.2%	9.3%	6.7%	7.0%	9.0%	10.5%
Hawaiian Electric	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	11.0%	10.9%	10.0%	10.0%	11.0%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	6.8%	3.8%	6.8%	9.5%	8.5%	8.5%
Pepco Holdings	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	11.0%	9.1%	7.0%	8.5%	10.5%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	10.0%	9.1%	8.5%	8.5%	8.0%
Puget Energy	12.4%	11.0%	8.8%	10.2%	10.2%	7.4%	11.5%	11.8%	13.2%	7.6%	7.8%	7.4%	8.0%	8.4%	10.4%	7.8%	7.5%	8.5%	8.5%
Average	11.3%	11.1%	11.8%	11.5%	10.5%	9.3%	10.6%	9.7%	10.3%	11.5%	11.4%	10.1%	10.7%	9.6%	**10.7%**	**10.7%**	**10.0%**	**11.2%**	**10.9%**
Composite															**10.8%**	**10.7%**			
Grant Comparable Gas Group																			
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	11.8%	14.0%	13.0%	12.5%	12.0%
Atmos Energy Corp	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	11.4%	10.2%	10.0%	9.5%	11.0%
Cascade Natural Gas	7.1%	11.0%	6.1%	8.2%	9.6%	9.2%	8.3%	12.1%	13.1%	13.5%	10.6%	8.5%	11.5%	7.8%	9.8%	10.4%	10.0%	1.5%	11.0%
Laclede Gas Company	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	11.3%	10.5%	12.5%	10.5%	9.5%
New Jersey Resources	12.1%	11.9%	13.0%	13.3%	13.8%	14.5%	14.6%	14.9%	15.1%	15.2%	15.9%	16.7%	15.8%	16.2%	13.8%	16.0%	12.6%	12.5%	12.0%
Nicor, Inc	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	16.2%	14.9%	14.0%	13.0%	12.0%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.5%	9.5%	10.0%	10.5%	10.5%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	13.0%	11.8%	11.0%	11.5%	12.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	12.2%	13.8%	13.0%	12.5%	13.0%
Southwest Gas	5.1%	3.9%	7.5%	0.6%	1.7%	5.4%	10.4%	7.5%	7.3%	6.7%	6.6%	6.2%	8.8%	6.5%	5.6%	7.0%	10.5%	9.5%	9.5%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	12.4%	11.5%	9.5%	10.0%	11.0%
Average	10.6%	11.8%	11.0%	10.9%	12.4%	12.3%	11.7%	11.2%	12.1%	12.6%	11.3%	11.9%	11.8%	11.3%	**11.6%**	**11.8%**	**11.5%**	**10.3%**	**11.3%**
Composite															**11.7%**	**11.8%**			

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	1992-2001 Average	2001-2005 Average
Comparison Group																
Cleco	177.3%	174.9%	156.2%	162.2%	167.8%	170.8%	182.5%	172.3%	222.8%	224.3%	154.1%	134.5%	176.9%	176.6%	181%	173%
DPL Inc	176.6%	206.0%	195.6%	213.1%	214.4%	221.4%	231.2%	215.4%	313.8%	403.9%	639.5%	241.3%	271.8%	318.5%	239%	375%
Duquesne Light Holdings	137.4%	150.8%	130.4%	150.6%	163.1%	165.4%	196.7%	205.2%	255.5%	217.2%	218.7%	220.8%	240.4%	217.9%	177%	223%
Empire District	184.2%	178.0%	142.9%	142.3%	142.7%	137.6%	168.0%	176.5%	183.2%	162.0%	131.7%	132.7%	143.7%	148.5%	162%	144%
Hawaiian Electric	170.8%	153.9%	141.2%	149.1%	147.0%	147.1%	154.1%	131.8%	126.7%	145.1%	153.3%	150.9%	178.8%	181.2%	147%	162%
Northeast Utilities	154.2%	149.4%	127.0%	123.5%	94.5%	64.3%	90.7%	113.3%	136.4%	129.0%	99.4%	95.3%	105.5%	108.4%	118%	108%
Pepco Holdings	159.6%	162.2%	135.5%	138.3%	160.7%	151.0%	161.3%	166.1%	138.8%	124.4%	109.9%	102.9%	109.2%	121.9%	150%	114%
PNM Resources	71.9%	83.8%	86.6%	95.3%	108.3%	105.7%	105.7%	84.9%	94.1%	122.7%	94.5%	93.5%	124.3%	147.2%	96%	116%
Puget Energy	149.2%	146.4%	111.7%	119.5%	130.0%	155.2%	169.7%	145.8%	143.4%	143.5%	125.9%	128.9%	137.5%	132.7%	141%	134%
Average	167%	169%	149%	157%	155%	151%	171%	169%	206%	214%	233%	163%	186%	192%	**171%**	**197%**
Composite															**177%**	**197%**
Grant Comparable Gas Group																
AGL Resources	181.0%	195.4%	169.2%	171.8%	189.1%	182.8%	183.4%	168.6%	167.6%	183.6%	171.2%	188.4%	184.0%	190.9%	179%	184%
Atmos Energy Corp	158.4%	193.5%	186.4%	195.7%	247.7%	241.4%	245.6%	216.5%	166.6%	170.4%	150.0%	152.3%	146.9%	144.9%	202%	153%
Cascade Natural Gas	171.6%	183.2%	156.3%	155.9%	155.7%	169.4%	164.6%	167.4%	162.2%	184.4%	185.9%	195.6%	204.1%	195.1%	167%	193%
Laclede Gas Company	158.3%	187.2%	178.2%	162.8%	167.7%	174.8%	174.5%	159.2%	141.2%	154.7%	145.1%	168.6%	179.4%	178.6%	166%	165%
New Jersey Resources	161.0%	185.5%	162.0%	178.9%	190.4%	228.5%	224.8%	224.0%	226.7%	223.6%	220.5%	244.4%	251.5%	274.6%	201%	243%
Nicor, Inc	178.9%	215.8%	194.6%	186.8%	220.0%	241.6%	259.6%	226.1%	226.5%	239.1%	198.9%	184.8%	210.0%	222.1%	219%	211%
Northwest Natural Gas	161.9%	175.8%	161.4%	145.8%	156.1%	173.3%	169.0%	140.6%	129.2%	132.9%	144.8%	144.0%	153.4%	171.8%	155%	149%
Piedmont Natural Gas	179.7%	213.6%	186.0%	181.6%	182.8%	216.6%	222.2%	212.9%	195.4%	198.9%	186.4%	211.3%	212.1%	207.7%	199%	203%
South Jersey Industries	154.2%	174.6%	141.0%	142.1%	145.7%	178.4%	208.5%	202.0%	195.9%	204.5%	185.4%	170.1%	195.2%	221.2%	175%	195%
Southwest Gas	81.3%	99.8%	102.7%	103.5%	121.0%	128.7%	139.3%	146.9%	120.4%	127.0%	123.4%	118.1%	126.9%	134.8%	117%	126%
WGL Holdings	173.5%	188.9%	165.4%	164.1%	178.3%	199.1%	197.1%	176.3%	177.5%	176.9%	152.4%	162.3%	175.0%	183.0%	180%	170%
Average	160%	183%	164%	163%	178%	194%	199%	186%	174%	181%	169%	176%	185%	193%	**178%**	**181%**
Composite															**178%**	**177%**

Source: Calculations made from data contained in Value Line Investment Survey.

Exhibit___(DCP-1)
Schedule 11

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2005

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
Averages:		
1992-2001	14.7%	341%
2001-2005	12.2%	299.2%

Source: Standard & Poor's Analyst's Handbook, 2006 edition, page 1.

Exhibit___(DCP-1)
Schedule 12

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Comparison Group	2.9	0.92	B+	B
Grant Comparable Gas Group	2.1	0.86	B+	B+
Unisource Energy	3.0	0.75	C++	B

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the latter representing the highest level.

UNS GAS
TOTAL COST OF CAPITAL

ITEM	AMOUNT ($000)	PERCENT		COST RATE			WEIGHTED COST	
Long-Term Debt	$98,859	55.33%		6.60%			3.65%	
Common Equity	$79,804	44.67%	9.50%		10.50%	4.24%		4.69%
Total	$178,663	100.00%				**7.89%**		**8.34%**
							8.12% Mid-point	

UNS GAS
PRE-TAX COVERAGE

ITEM	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST
Long-Term Debt	55.33%	6.60%	3.65%	3.65%
Common Equity	44.67%	10.00%	4.47%	7.44% (1)
TOTAL CAPITAL	100.00%		8.12%	11.10%

(1) Post-tax weighted cost divided by .6 (composite tax factor)

Pre-tax coverage = 11.10%/3.65%
3.04 X

Standard & Poor's Utility Benchmark Ratios:

	BBB	A
Pre-tax coverage (X) Business Position:		
5	2.4 - 3.5x	3.5 - 4.3x
Total Debt to Total Capital (%) Business Position		
5	50- 60%	42 - 50%

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPOERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

REDACTED

DIRECT

TESTIMONY

OF

GEORGE E. WENNERLYN

ON BEHALF OF

ARIZONA CORPORATION COMMISSION STAFF

FEBRUARY 9, 2007

TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NOS. G-04204A-06-0463 ET AL

I have been asked by the Arizona Corporation Commission Staff to perform a general review of the UNS Gas PGA: preparing an historical record of prices paid by the Company, comparing supply purchases to hub pricing, evaluating the UNS Gas decision making process to supply selection and other related findings. My assessment of prudence and reasonableness covered the period of September 1, 2003 and ending December 31, 2005.

From this review came the following findings and recommendations:

1. The UNS Gas natural gas procurement, practices, and policies achieved the appropriate objectives of a purchasing strategy which balances reliability, cost, and price stability. The purchases were reasonable and prudent for the review period.

2. There are a number of improvements which the Company can make on a going-forward basis that should enhance the Commission Staff's purchasing review process and understanding, involving the monthly Purchase Gas Adjustor filings. The Commission should require UNS Gas to include the additional pieces of information outlined in my testimony.

3. UNS Gas needs to complete a study of the costs and benefits of the present gas supply arrangement with BP Energy as compared to other market suppliers, and present their findings to the Commission for review and complete understanding.

I. INTRODUCTION

Q. Please state your name, and business address.

A. My name is George E. Wennerlyn and my business address is 1549 Grosse Point Drive, Middleton, Wisconsin 53562.

Q. Please state your reason for involvement in this proceeding.

A. I am testifying on behalf of the Arizona Corporation Commission, Utilities Division.

Q. Please advise the Commission on your qualifications.

A. I have over 38 years of experience in the energy and natural gas industry. Following graduation from the University of Minnesota with a Bachelor of Science in Business Administration degree, I went to work at the Wisconsin Power and Light Company. During my 26 years of employment with the utility, I held supervisory and management positions in the areas of electric and natural gas rate design, natural gas engineering, and natural gas supply planning and purchasing. My involvement in these functions began in mid-1980 as natural gas was being deregulated. Additionally, I served as director for A&C Enercom Consultants, Inc., a consulting firm acquired by WP&L Holdings to supply energy-related services to the electric and gas utility end-users. Finally, in 1996 I formed my own consulting firm named Select Energy Consulting, LLC (SEC). My firm assists commercial, institutional, and industrial clients in natural gas supply planning, cost-benefit analysis, contract development, and gas purchasing. I also monitor the state regulatory process for rate making and policy changes that would impact client interests.

In 2003, SEC and MSB Energy Associates (MSB) teamed up to provide expert analysis of the risk management strategies of an electric utility's purchases of natural gas for electric generation in the state of Wisconsin. The utility had proposed a plan to manage gas costs through financial means and requested recovery of $1.5 million in rates. On behalf of the Citizens' Utility Board, we analyzed the plan and the likelihood that it would result in ratepayer benefits, and concluded that it would not be in the ratepayer interests given the proposed strategies and the gas markets.

Similarly, in 2004 MSB and SEC once again joined forces in Southwest Gas Corporation Docket No. 03-12012 on behalf of the Staff of the Public Utilities Commission of Nevada. We were asked to assess the prudence and reasonableness of gas purchases for the historical period beginning February 1, 2003 and ending January 31, 2004; the hedging and other financial options used to manage gas price risk including alternatives to simply paying the gas inventory charge; and to investigate Southwest Gas' policy to diversify gas supply by various basins.

The Bureau of Consumer Protection (BCP) for Nevada requested our involvement in Docket 04-7004 to review, advise and present testimony on the Energy Supply Plan 2004-2006 (Volume III) filed by the Sierra Pacific Power Company (SPPC). We also testified on behalf of the BCP regarding Nevada Power Company's (NPC) Energy Supply Plan in Docket 04-9004. Again in 2005, the BCP asked MSB and SEC to review and present testimony based on our findings on SPPC's Energy Supply Plan filed for 2006-2007 in Docket 05-9016.

Attached is Exhibit GEW-1 which provides expanded detail of my professional background.

Q. What is the purpose of your testimony?

A. We have been asked by the Arizona Corporation Commission Staff to focus on the following issues in this docket for UNS Gas, Incorporated (UNS Gas or the "Company"):

I. Perform a general review of the UNS Gas PGA, and prepare an historical record of prices paid by the Company and evaluate the supply purchases for reasonableness based on hub pricing and other available industry data.

II. Evaluate the UNS Gas hedging policies and procedures for reasonableness.

III. Evaluate the UNS Gas decision making processes and procedures in bidder award and evaluation. This will include, but is not limited to, an evaluation of the UNS GAS internal approval process and the presence and execution of internal checks and balances.

IV. Determine if the use of the same personnel to procure gas for UNS and TEP poses "code of conduct issues" and /or "conflict of interest" issues.

V. Examine the UNS Gas interstate pipeline capacity portfolio and the Company's management of its pipeline capacity.

VI. Review and analyze the UNS Gas natural gas procurement policies and procedures for reasonableness and prudence. Assessment of prudence and reasonableness of gas purchases for historical period beginning September 1, 2003 and ending December 31, 2005.

In this testimony, I will address the above. My associate, Mr. Jerry Mendl of MSB Energy Associates will address the assessment of the Company's gas purchase timing practices which is part of issue VI.

Q. How did you evaluate the UNS Gas natural gas purchasing practices and the reasonableness of their acquisitions?

A. The first step in evaluation was to develop a background understanding of the Company's purchasing practices. A series of questions were developed to gain that understanding. Commission Staff then submitted a series of discovery questions to the Company. Following the receipt of responses, additional analysis ensued. On July 12, 2006 an on-site meeting was held at UNS offices in Tucson involving Commission Staff and UNS Gas personnel. This encounter allowed for the opportunity to obtain a more complete understanding of purchasing activities, pipeline issues, internal risk management, approaches, and the Company's purchasing strategies.

From this review process developed a period of in-depth analysis to look into the many issues of gas purchasing to complete the portfolio of supplies required to meet system demands.

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q, Would you please summarize your testimony and recommendations?

A. Yes, I will with the following conclusions:

1. My review of the UNS Gas natural gas procurement, practices, and policies determined that the Company achieved the appropriate objectives of a purchasing strategy which balances reliability, cost, and price stability. The purchases were

reasonable and prudent. This finding covers the period of September 2003 through December 2005.

2. From key audit findings there are a number of improvements which the Company can make on a going-forward basis that should enhance the Commission Staff's purchasing review process and understanding involving the monthly Purchase Gas Adjustor (PGA) filings. The Commission should require UNS Gas to include the following additional pieces of information in each monthly filing:
    a. Copies of EPNG's and Transwestern's monthly Allocation Statements.
    b. Specific hedging detail for each gas purchase transaction.
    c. Notational (written) information for each transaction (hedges) on the monthly supply invoice(s).
    d. Automatically submit complete documentation required for Commission Staff to complete a reconciliation of the monthly PGA.

3. Under the current contract structure with BP Energy, the energy supplier acts as an agent and manager for both required gas supply and pipeline responsibilities. That relationship may or may not serve the best interests of the retail customer from a cost-perspective. Recently approved pipeline changes (January 2006) have increased daily obligations by UNS Gas personnel that were previously handled by BP personnel. UNS Gas needs to complete a study of the costs and benefits of this supply arrangement versus other market options, including the use of other gas suppliers. They should present their findings to the Commission for review and complete understanding.

III. MONTHLY REVIEW OF THE UNS PURCHASE GAS ADJUSTOR (PGA) FILING

Q. Would you please discuss your analysis of the UNS Gas monthly PGA filing for the September 2003 through December 2005 period?

A. Yes, I will. Commission Staff requested a general review of the UNS Gas PGA, including the comparison of historical prices paid by UNS Gas to actual market prices at commonly used pricing points. The objective of this review was to make a determination regarding the UNS Gas purchases in terms of reasonableness and prudence.

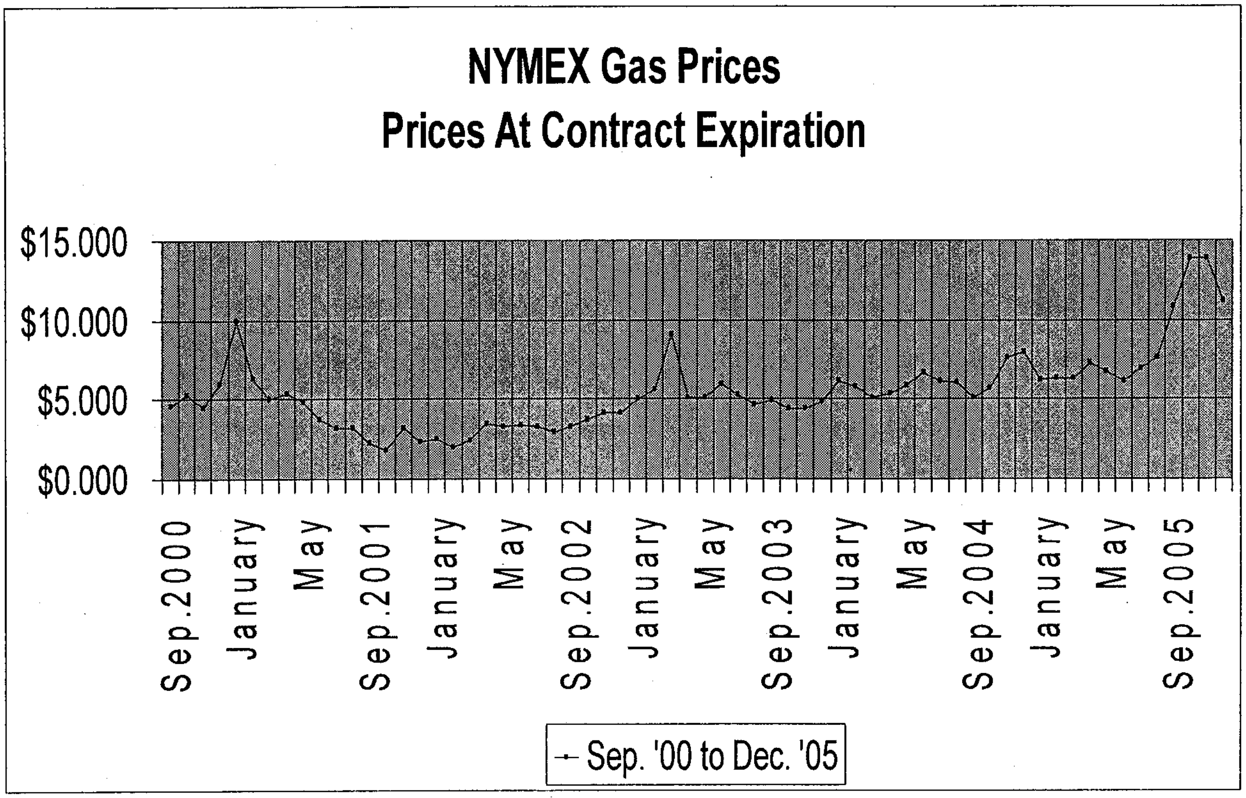
To complete this step, the submitted PGA monthly filings were used as the reference source with a focus on the prices paid for natural gas for the Company's retail customers as compared to hub pricing at the points of purchase. In making this analysis, it was important to isolate the gas costs in such a manner as to insure that comparable cost comparisons remained valid. The actual UNS Gas monthly gas costs were compared to the first-of-the-month published gas prices (hub prices) at the major purchase points used by the utility. The purchase points included the San Juan basin, the Permian basin, and Waha. Additionally, each hub price was weighted by the actual volume of gas purchased at that point without the cost of transportation from the hub to the UNS Gas city-gate. Also excluded from this comparison were the incurred costs of non-retail utility customer's (Negotiated Sales Plan (NSP) customers) and interest charges on select carrying accounts. Effectively, the comparisons were only comprised of commodity costs.

Referring to Exhibit GEW-2 you will find a table which displays the results of the price comparisons. Included in the analysis are the price variances and the monetary impacts of those differences for each month, for the review period, with partial and whole calendar year running totals.

Q. What interpretations did you make for the price comparisons reflected in the exhibit?

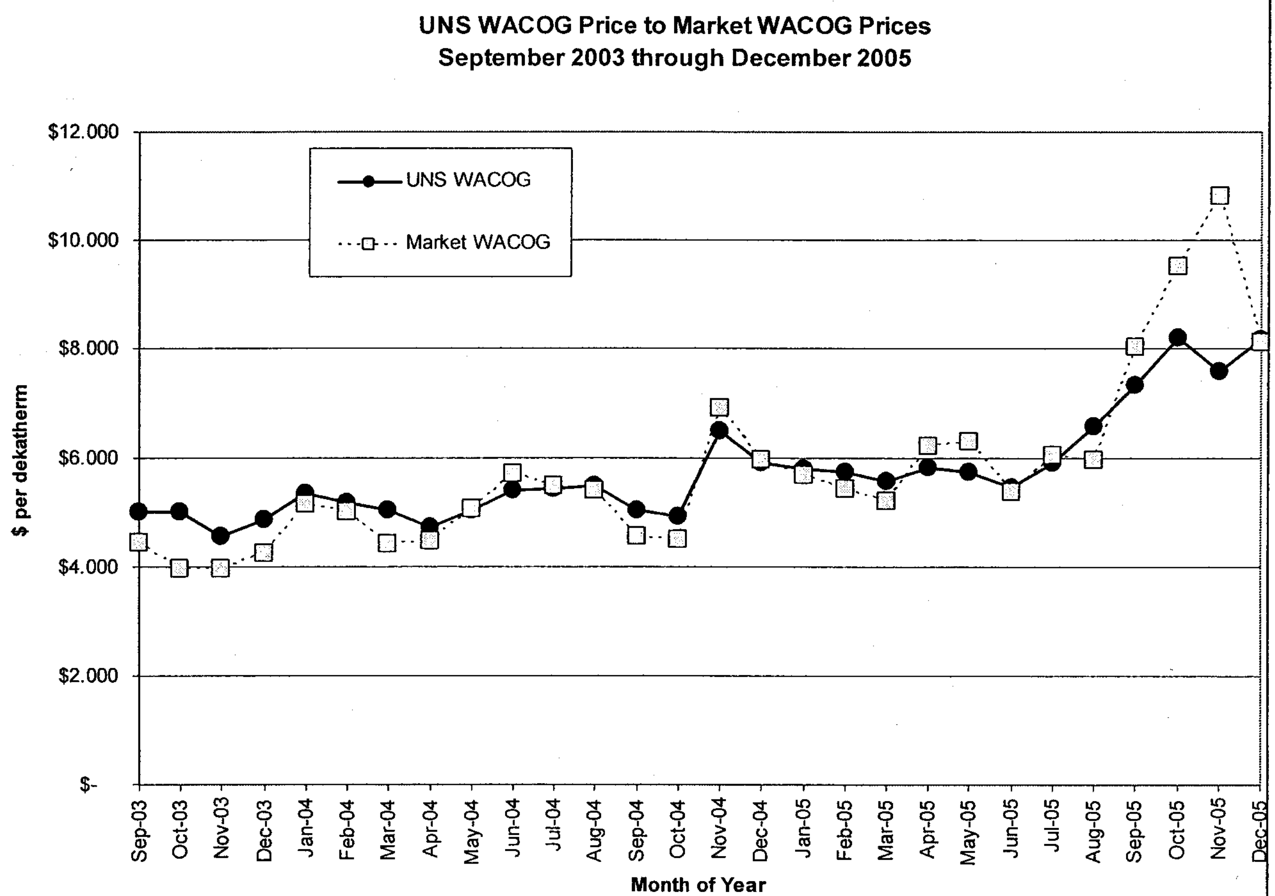
A. Early in the review period (following the acquisition of the gas utility from Citizens Communication Company – Arizona Division), the utility's weighted-average cost of gas was above the comparable hub prices used for its gas supply. I do not believe this was a function of ownership differences but simply the results of earlier purchases and market trends in gas prices. Citizens' gas purchasing practices were similar to those followed by UNS Gas after the acquisition. Both had a plan to begin acquiring a portion of required gas supplies 36 months in advance of actual deliveries.

Looking at the chart below of monthly natural gas prices listed on the New York Mercantile Exchange (NYMEX) will help to address this comparison and the general understanding of price trends. While NYMEX prices do not translate into actual prices paid at San Juan, Permian, or Waha, there is a high correlation (generally above 90%) between the price movements, which simplifies the comparison to one hub (NYMEX) rather than to multiple hubs (San Juan, Permian, Waha).



The initial "above market" price comparisons in the exhibit are difficult to determine given the change in ownership, coupled with early purchases. As you can see in the graph above, the NYMEX `price trend was moving upward prior to September 2003, followed by a brief price decline that ended in December 2003. Comparisons of UNS Gas prices for the September 2003 through April 2004 period were not very favorable to first-of-the-month market prices. In fact, the unfavorable trend continued into early 2005 when the entire energy complex came under price pressure due to increasing oil prices. Then, the advanced purchases made by UNS Gas proved valuable to retail customers from a cost viewpoint. The summer hurricanes of 2005 (Katrina and Rita) caused dramatic price increases and price volatility, which the UNS Gas purchase strategy significantly dampened.

Below is a graph of UNS Gas' weighted-average cost of gas as compared to the first-of-the-month weighted-average cost of gas at the pricing hubs (Permian, San Juan, and Waha) covering the September 2003 to July 2006 period. UNS Gas relies primarily upon these hubs for its gas supplies and the pricing curve below reflects their actual percentages purchased from each hub for the respective months shown:



If retail gas were acquired using a first-of-the-month purchase strategy rather than the 36-month advance purchase strategy, the results reveal that in 17 months of the 28 month review period UNS Gas prices were above market.

Q. Were these comparison results surprising to you?

A. No, they are not. I would expect these comparison patterns will continue in future months as gas prices trend either upward or downward. Generally there will be a lag in UNS Gas retail prices in both price trend directions, with Company prices either above current market prices or below current market prices given the 36-month strategy. UNS Gas follows a purchase plan which includes both "non-discretionary" (must acquire) and "discretionary" (may acquire) advanced purchases for any delivery month. The actual degree of lag may be influenced by the amount of "discretionary" gas purchased by the Company for that month.

Q. Would you summarize your comments on the reasonableness of the above price comparisons?

A. Yes. As you can see in the above graph, on a month to month basis there is a "cost" to the 36-month purchasing strategy followed by the utility. Here, I define "cost" as the difference between the UNG Gas average cost of gas for the month and the first-of-the-month cost of gas at market hub prices.

However, raw price comparisons need to be weighted by the volumes of gas purchased for each of the months in order to determine the actual cost or benefit to the retail customer. When the above price differences and volumes are factored in together, the comparison results become more favorable:

Year	UNS Gas costs to WACOG Hub prices
2003 (partial: Sept. – Dec.)	+13.8% more
2004	+ 1.7% more
2005	- 5.8% less
Entire 28 month period	- 0.7% less

For the entire 28-month period the resulting -0.7% (less costly) is very acceptable in my opinion. I would find a value of +20% in added cost (commodity only) for an extended period of time (twelve month period) to be a point where a re-evaluation of the established purchasing strategy would be merited. This 20% variance is completely arbitrary reflecting my values and expectations. For others who monitor price comparison performance (UNS Gas, Commission Staff, Consumers) the percentage variance may be more or less.

Q. Please clarify your comments regarding a re-evaluation of the established purchasing strategy.

A. I believe that a natural gas purchase strategy needs to be viewed as a living document, one that needs to be revisited throughout the year. I believe this approach is required given the ever changing conditions found in the marketplace. For example, following the hurricanes of 2005 the price for natural gas increased substantially. Unlike UNS Gas, a utility who relied upon the use call options as part of their own price stabilization policy, that strategy would quickly be called into question given the high financial transaction cost of an option. Circumstances quickly changed, resulting in a review of purchase policies for some utilities, necessary to insure that what had been established should continue to be followed.

Once a set purchase plan is in place, you cannot place that process on auto-pilot control. You must review and insure that what is in place still makes sense to do. If you fail to do so, your actions and inactions may become imprudent from a customer's viewpoint.

Q. When reviewing the monthly PGA filings, did you encounter any problems in reconciling the costs to the natural gas quantities included in the report?

A. Yes, I did encounter problems in matching volumes that appeared on the monthly BP supply invoice to the volumes and charges received from the two pipelines (EPNG and TW).

Understandably, the monthly invoice from BP reflects scheduled delivery volumes (which are estimates of required monthly supply) and not actual consumed volumes (metered-measured). This process is followed by BP and the Company in order to insure a timely billing process which reduces the lag time until all gas volumes are verified and balanced. Each month UNS Gas personnel complete this review and make corrections accordingly. Thus, when scrutinizing any monthly supply invoice, you will invariably find hand-written changes in volumes delivered as compared to volumes consumed (measured). Thus, the dollar amounts billed change as well. The BP invoice, with the noted adjustments (corrections), is included in the filed PGA.

Q. Can you provide an example of this monthly reconciliation process of the BP invoice?

A. Yes, I can. For the month of December 2005, the table below summarizes the original invoice to reconciled BP invoice:

BP Energy	Original Invoice	Reconciled Invoice	Percent Variance to Original Invoice
Volume (Dths)	[redacted]	[redacted]	+4.6%
Amount Billed ($)	[redacted]	[redacted]	+1.0%

The pipelines also issue monthly invoices to UNS Gas and both are included in the monthly filed PGA. The documents are required to complete any reconciliation; however, they are not sufficient to complete reconciliation with the billed (after adjustments) volumes which appear on the BP invoice.

Q. What additional information is required?

A. For a complete reconciliation, the monthly El Paso Natural Gas Allocation Statement and the monthly Transwestern Pipeline Company Contract Balance Statement are required as they show the "scheduled" volumes as compared to the actual "measured" (metered) volumes. The difference between the two totals represents the imbalances between scheduled and actual deliveries.

Q. Is there a simple resolution to this information requirement?

A. Yes, there is. UNS Gas should be required to automatically include the additional statements (and other documents that evolve as pipeline services change) when filing the monthly PGA.

Q. Is there any other information that is needed to adequately complete the monthly PGA reconciliation?

A. Yes. The monthly BP invoice lacks adequate information necessary to link the multiple gas purchase transactions which take place prior to the delivery month. As a result, it is difficult to match actual purchases (advanced hedges) to the quantities appearing on the invoice. To facilitate the regulatory review process, UNS Gas should be required to add written notes on the supply invoice linking that specific transaction detail to a specific purchase. In response to one of our data requests, UNG Gas provided a form used by UniSource Energy Services titled "Hedging Activity Detail". That form, or similar information included from that form, should be included with each PGA filing

Q. Prospectively, should the Commission order other PGA filing requirements on UNS Gas?

A. Yes. The Commission should request that all necessary documents required for completing a reconciliation of supply invoices and pipeline statements be automatically included with each filing.

IV. EVALUATE THE UNS GAS HEDGING POLICIES AND PROCEDURES FOR REASONABLENESS

Q. Please present your evaluation of the UNS Gas 36-month hedging policy.

A. To answer that question, I would like to refer you to Exhibit GEW-3 which presents the actual contracts entered into by UNS Gas for the period of review. This exhibit looks at each individual purchase, and compares that purchase to the New York Mercantile Exchange (NYMEX) futures market prices which existed for that specific month over the "36-month life" of that particular contract. The phrase "36-month life" is based upon the Company's written policy of when they will begin purchase of a specific month's supply requirement. It does not reflect the actual "life" of a NYMEX contract and could be different for any other utility that followed a different purchase strategy.

The comparison calculates the total cost of the gas package the Company acquired and measures that value to the highest and lowest price established during that same 36-month purchasing period.

From these three calculations, I then develop a "ranking index", which measures (as a percentage) where the actual purchase falls along the continuum between the 36-month highest NYMEX price and the 36-month lowest NYMEX price in the defined purchase period.

Q. How do you account for that basis adjustment factor, which reflects the price difference between the San Juan or Permian pricing hubs and the NYMEX price which is at the Henry Hub?

A. The "basis differential" must be removed from the actual purchase price in order to make the transactions comparable to the NMYEX prices, which are quoted at the Henry Hub in Louisiana. You must remove the adjustment from the trigger price before comparing the NYMEX equivalent price to historic high and low prices. You need to insure an "apples to apples" comparison.

Q. Please explain the rationale for using this type of hypothetical comparison.

A. Each monthly contract traded on the exchange (NYMEX) has a trading life of some 6 years. Currently, as an example, one could purchase gas utilizing a NYMEX contract for the month of December in the year 2012. For the entire time period until the date arrives where December 2012 can no longer be traded (upon settlement in November 2012), the pricing history for that specific month contract is being tracked. Between the present date and the ending date there is always the potential that either a new high or low price will be established.

With that in mind, a natural gas buyer has the opportunity to buy that NYMEX contract at anytime during its "life". Based on one's purchase strategy, judgment, timing, and good or not-so-good fortune, a buyer could end up purchasing that contract at a pricing point anywhere along the continuum between the highest price and the lowest traded price. For UNS Gas, this NYMEX comparison provides a view to a 36-month purchase horizon, given the Company's strategy is based on that timeframe. Indeed, you can measure or "rank" any given purchase by comparing the price you triggered to the actual life high and low price values or any other defined period, such as 36 months.

For purposes of understanding, an example helps to show the value of the comparison. The formula is:

$$\% \text{ Ranking} = \frac{(\text{Actual Price “at NYMEX”} - \text{Lowest 36-month Price})}{(\text{Highest 36-month Price} - \text{Lowest 36-month Price})}$$

For example, assume you buy one unit of gas per day for December 2005, at a cost of $8.40 per unit. The NYMEX contract cost for the month would be $260.40 or (1 unit * 31 days * $8.40). If, however, you had purchased that contract at the lifetime high price which was $14.67, then your cost for the month would have been $454.77 (1 unit * 31 days * $14.67). Or, perhaps with good fortune you purchased the one unit of gas at the lifetime low of $3.99 per unit. The cost of that contract would have been $123.69 (1 unit * 31 days * $3.99).

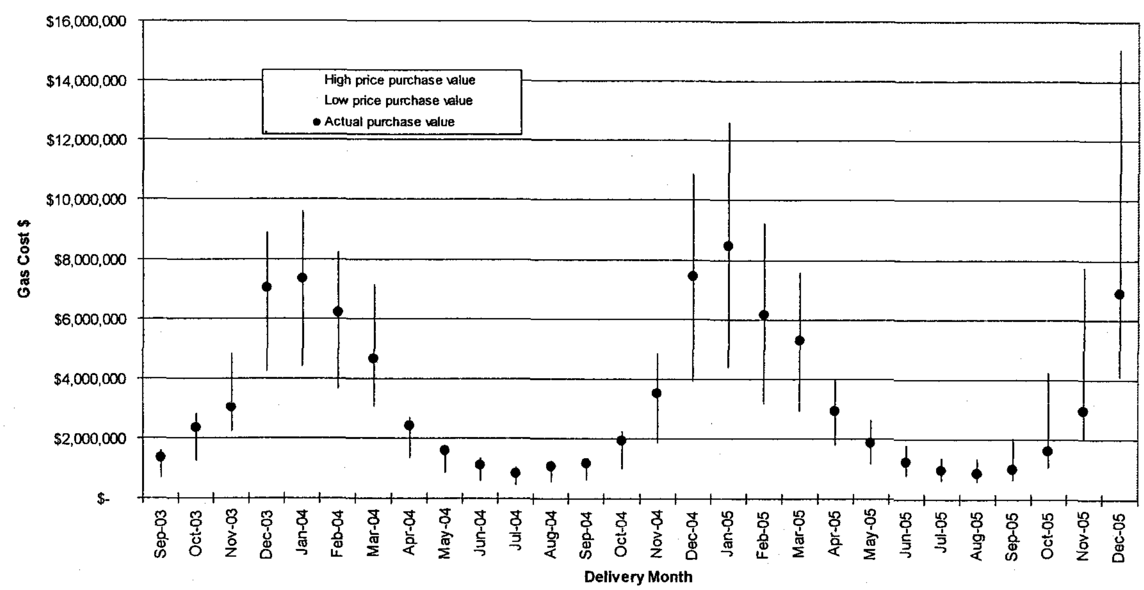
To determine the "ranking" of your purchase you would follow the above formula and calculate the difference between the 36-month high cost of the purchased package and the calculated lifetime low cost. Then, take the actual purchase price you made (at NYMEX) and also subtract the low 36-month price package cost. The lowest lifetime price serves as the benchmark for measurement purposes, as it would be the most preferred price by any successful natural gas buyer. So, for our example above, the ranking of the one December 2005 purchase would be:

($260.40 less $123.69) divided by ($454.77 high less $123.69 low) =41% ranking

It is important to keep in mind that in ranking purchases with the lowest price being used as the benchmark, that the 0% (the lowest price) value is the most preferred and 100% (the highest price) value is the least preferred. Interpreting either individual or annual purchases, if you bought gas at a point that is less than the mid-point of 50%, but above the optimum level of 0%, most analysts would view the result favorably if corroborated by other cost comparisons. In addition to looking at individual purchases, you can also calculate combined purchases to arrive at an overall ranking for the period under review.

Below is a graph which reflects this analysis of high and low prices for the 36-month period of the NYMEX contract. UNS Gas's purchases garnered a ranking which ranged from a one-month high of 81% (May 2004) to a one-month low of 17% (November 2005) on the graph. Overall, the ranking for UNS was 48% for the entire 28 month period of review.

**Natural Gas Cost at 36-Month High Price,
36-Month Low Price and Actual Price
September 2003 through December 2005**



Q. Is this ranking an indication of purchasing quality?

A. No, it is not meant to be a solitary quality measurement. It can be used as an indicator of purchase quality, but only if other analysis supports that finding.

Additional analysis needed to support this measurement would include understanding how the UNS Gas - NYMEX purchase price compared to the average price established over the 36-month life of the NYMEX contract. While the above described ranking of purchases provides a quantitative tool to evaluation, there can be distortions to price that could impact this analysis. For instance, one only needs to look back at the NYMEX contract for the month of March 2003. Just one month before the March contract expired, the high lifetime price was $5.75. However, during the last days of trading in February 2003, based on market fears relating to supply adequacy, the market spiked to a new high of $11.899. Depending on when a gas buyer purchased a March 2003 NYMEX contract, the results could be very misleading. Therefore, it should be used as one component in a larger review that includes other market perspectives, such as prevailing prices over time, and price comparisons to supplies available at different resource basins. During the actual UNS Gas review period, the hurricanes of 2004 and 2005 created similar price impacts.

Q. Did you review the Company's use of financial instruments to manage price risk?

A. Yes, I did. Presently, UNS Gas purchases approximately 45% of their total gas requirements using the financial instruments of hedging gas futures and basis swaps. UNS Gas does not directly enter into these transactions, but indirectly through their supplier. To further eliminate price risk, there are other risk management tools which can be utilized including the use of call options and price collars, to name a few. However, the use of these instruments does not insure that all risks will be avoided or gas costs minimized. On the contrary, they can have an incremental impact through additional staffing or outsourcing requirements, along with the cost of the financial instruments. Moving beyond the current utilization level of financial tools requires clear definition to protect the customers and the Company. This includes a multitude of issues, from the separation of the accounting and the purchasing functions as it relates to financial transactions, to the required protections needed to prevent speculation. All need to be defined to prevent harm both consumers and UNS Gas shareholders. An example of a potential activity that could cause harm would be the acquisition of a stand-alone put option, a sign that speculative trading might be present. That should not be part of a utility's gas purchasing activity.

Prior to expanding the use of additional financial alternatives, considerable effort by all stakeholders will be required to define the boundaries necessary to implement such a strategy. Until that process is complete, in my opinion, the present use of financial instruments (third party hedging and swaps) for the purchase program is sufficient. This already represents 45% of the gas portfolio.

V. EVALUATE THE UNS DECISION MAKING PROCESS FOR GAS SUPPLY SELECTION

Q. Please describe you investigation into supplier selections and contract awards.

A. UNS Gas assumed a gas supply contract when acquiring the Citizens Communication Company – Arizona Gas Division in 2003 which was served by BP Energy Company (BP). The contract term ended in August of 2005. However, under the provisions of the supply contract, the agreement could be extended by the utility year-to-year which they have elected to continue.

Under the agreement, BP acts as an agent of UNS Gas, purchasing gas supplies and managing the transportation services received from the pipelines that have contractual relationships with UNS Gas. The pipelines include El Paso Natural Gas (EPNG) and Transwestern Pipeline Company (TW). BP orders gas as requested by the Company and optimizes idle pipeline capacity for the utility, selling-off unused capacity to a third party. If BP is successful in that activity, both UNS Gas and BP share in the revenue from that capacity sale on a 50/50 basis. BP also assumed full responsibility for any imbalances that may exist on upstream pipelines. In effect, BP provided full requirement supply services to UNS Gas.

Q. Do those same services exist today between BP and UNS Gas?

A. No, they do not. The roles and responsibility changed due to new EPNG tariff and service proposals. The supply agreement between BP and UNS Gas was altered to reflect these changes, effective starting January 1, 2006.

Q. Did you discuss this arrangement with BP at your meeting with UNS personnel?

A. Yes, we did. During the discussions on supply acquisition UNS Gas reviewed the on going changes that were being made due to operational changes on the EPNG pipeline. The Company indicated that given the changes with daily nominations and balancing issues that the role of UNS Gas personnel was changing, too. No longer was BP able to manage the daily gas dispatch responsibilities with the pipeline without closer daily scrutiny and daily through-put estimates from the Company. Included in the modified agreement, UNS Gas is now responsible for differences between forecasts and actual usage and the cost of those variances. Additionally, UNS Gas relies more on the daily spot index for added supply needs. As a result, UNS Gas indicated that a review of their current contract was planned sometime in the future.

Q. Do you believe such a study should be conducted by UNS Gas?

A. Absolutely. The Company needs to determine if managing the entire spectrum of daily responsibilities for a typical gas distribution company would provide a financial benefit to its retail customers. Operating with total and direct responsibility, UNS Gas would be required to solicit gas supplies from a number of prospective gas suppliers, and determine if more competitive pricing would be available to them rather than sole reliance on BP. Additionally, the Company would assume full responsibility for both purchasing and selling unused pipeline capacity to address seasonal fluctuations without the 50/50 sharing mechanism the two parties presently follow.

The Commission should request and review the study results to insure that the interests of the retail customer are being maximized by the present contract relationship with BP.

VI. DETERMINE THE USE OF UNS PERSONNEL IN PROCURING GAS SUPPLIES FOR UNISOURCE ENERGY ENTITIES AND EVALUATE POSSIBLE "CODE OF CONDUCT" OR "CONFLICT OF INTEREST ISSUES".

Q. Did you look at the use of Company personnel in procuring gas supplies for the gas utility, UNS Electric, and Tucson Electric Power Company (TEP)?

A. Yes, we did. During our joint meeting with Company personnel we reviewed internal reporting relationships, the management of the various internal functions, the approval process and execution of internal checks and balances. The Fuels & Wholesale Power Department for UniSource Energy handles the functions of coal and rail contracting, natural gas and transportation, contract management and accounting, and fuel procurement activities. The organizational structure is similar to other combination gas and electric utilities, with combined purchasing activities carried out by one office for the entire Company.

What currently makes the UniSource Energy organization unique to other combination utilities are the supply arrangements in place for UNS Gas, TEP, and UNS Electric. For UNS Gas, the previously mentioned BP contract which transfers a portion of the daily management activities to another entity (BP) whereas a combination utility normally manages the daily functions for supply acquisition and pipeline capacity management. Similarly, UNS Electric has a full requirements contract with Pinnacle West, a relationship which extends into mid-2008. And for TEP, they hedged their own gas supplies but do not procure nor schedule the deliveries, as that function is provided by Southwest Gas Company.

Q. What codes of conduct are followed by the Fuel & Wholesale Power group?

A. Our review of UNS Gas procurement activities included an understanding and assessment of the UNS Gas' Price Stabilization Policy. This written policy appears in the Company's Exhibit DGH-1. The policy states the Company's plan objectives, the hedging procedures of the UNS Gas unit, levels of purchase authorization, the assignment of transaction responsibilities and related job functions by company position, organizational levels of approval, and management reporting. Each employee is required to know and provide signed acknowledgment of their compliance with the stated policies. In my view, the policies clearly and adequately define the appropriate functions and position responsibilities necessary to carryout a fuel procurement activity.

Q. Do you see any potential conflicts of interest within the UNS Gas organization, and specifically the Fuels & Wholesale Power group?

A. No, I do not. In a data request, UNS Gas provided a copy of the UniSource Energy Corporation's Energy Risk Control Policies Manual which outlines the risks relating to wholesale power trading, and fuel and power procurement. The manual defines lines of authority, responsibility, and accountability related to energy procurement, trading and marketing. Moreover, the manual defines the risks, including internal administrative risks, market price risk, accounting and tax related risks, and regulatory risks. These risk control policies are incorporated into the separate policies followed by UNS Gas, UNS Electric, and TEP. Important to any potential conflict of interest, the manual describes the internal organization structure and the deliberate separation of job functions. Commonly called the "front", "middle", and "back" offices, functions are organizationally structured to separate different job activities. For instance, the energy trader function is a separate position as compared to the position of a risk manager. Additionally, the credit manager organizationally reports to an entirely different part of the corporation.

Between these two documents, the Company has outlined justifiable standards of conduct. Moreover, there was no indication of problems associated with the day-to-day conduct of business during our interview with UNS Gas personnel.

I would like to make one final comment relating to the area of conduct and potential conflict. Given the current fuel procurement relationships established with BP, Southwest Gas, and Pinnacle West, coupled with the defined policies which the Company has established internally to insure compliance and avoid risk, I believe there is less concern or chance for collusion or misconduct. One could argue that changing roles with supplier BP, Southwest Gas, or Pinnacle West could heighten the potential to these two concerns.

That might raise the level of concern and result in greater scrutiny. However, for the moment I believe the established safe guards are in place to minimize that potential.

VII. EXAMINE THE UNS GAS INTERSTATE PIPELINE CAPACITY PORTFOLIO AND THE MANAGEMENT OF ITS PIPELINE CAPACITY.

Q. Did you complete a review of the UNS pipeline portfolio?

A. Yes I did, both in general terms and comparisons between pipeline contractual rights and peak-day experience during the review period. Data requests were submitted to learn about the month-to-month demands on the UNS Gas system which focused on the upstream pipeline contracts, and rights to capacity for the core markets. In my review it became obvious for the short-term, that firm peak-day capacity becomes tight during the months of October and November. This means that reserves are narrowed to less than ±10%. This finding was confirmed by UNS Gas personnel when they discussed the strategy for rectifying the situation. In addition to the constrained months, the growth on the "Phoenix lateral" needs to be addressed as well. The communities located between Flagstaff and Phoenix (off the TW pipeline) have experienced considerable growth in recent years. UNS Gas personnel outlined the on-going discussions with the pipelines, their plans for reconfiguring the pipeline contracts, contract expiration dates and opportunities for capacity acquisition and release.

This strategy discussion covered the short-term and long term (current through 2018 horizon) planning period. UNS Gas addressed the current pipeline portfolio they manage and outlined the challenges and plans for the future to insure adequate coverage for core market customers for future years. Also covered in this discussion by UNS Gas was the consideration of fully managing the pipeline capacity and scheduling responsibilities, following a corporate review.

I believe the Company is adequately addressing the pipeline capacity and related issues.

Q. Does UNS Gas complete a periodic forecast of system requirements and contract capacity rights?

A. Yes, they do. UNS Gas completes a peak-day forecast for their system at the gate station level. I reviewed that forecast specifically for the April 2004 through March 2005 period and found that the variance between forecast and actual through-put was less than 2% for the 12 months.

Q. What importance does load forecasting have relating to monthly pipeline costs and penalties?

A. Load forecasting plays an increasingly important role in monthly pipeline costs, which the Company recognizes and is addressing. Chiefly due to tariff changes on the EPNG pipeline system, scheduled gas supplies need to be closely in balance to minimize daily costs. Moreover, the Company is also subject to hourly imbalances as well. Therefore, UNS Gas personnel must monitor daily and hourly needs attempting to keep consumption as close to estimated needs as possible.

In the Company's direct testimony, witness David G. Hutchens discusses the EPNG rate case that went into effect in January 2006, subject to refund. Under the pipeline's proposal, daily imbalance penalties would be imposed for variances between daily estimates and actual takes. Thus, the increased importance of load forecasting becomes apparent. UNS Gas will be required to alter their purchasing strategy to minimize this potential increased cost. This will include a higher reliance on hourly and daily system monitoring, frequent load forecasts, and use of spot market gas purchases. Additionally, increased pipeline capacity rights may be required to avoid penalties.

Q. Will these EPNG changes impact UNS Gas in others parts of their organization?

A. Yes, in all likelihood the changes will not only impact the daily functions as discussed above, but may have an impact on the present relationship UNS Gas has with their present supplier, BP. With additional responsibilities shifting to the Company that were once fulfilled by BP, the potential for increased personnel to assume those roles becomes apparent. UNS Gas will need to measure the overall impact of these changes, integrating the operational and personnel impacts into the supplier study I have recommended.

VIII. RECOMMENDATION SUMMARY

Q. Would you please summarize your testimony and recommendations?

A. Yes, I will with the following conclusions:

1. My review of the UNS Gas natural gas procurement, practices, and policies determined that the Company achieved the appropriate objectives of a purchasing strategy which balances reliability, cost, and price stability. This finding covers the period of September 2003 through December 2005.

2. In making this above statement, there are a number of improvements which the Company can make when filing the monthly Purchase Gas Adjustor filing which should enhance the Commission's gas cost review process, including:

a. Copies of EPNG's and Transwestern's monthly Allocation Statements.
b. Specific hedging detail for each separate supply purchase which appear on the monthly supply invoice.
c. Written information on the monthly supply invoice(s) identifying each specific purchase (advance hedge).
d. Automatically submit complete documentation required for Commission Staff to complete a reconciliation of the monthly PGA.

The Commission should require these additions to the PGA filings.

3. NS Gas needs to complete a study of their supply arrangement with BP Energy, where BP acts as an agent and manager of both required supply and transportation responsibilities, to see if continuance is in the best interests of the retail customer from a cost perspective as compared to other suppliers. The Commission would review the findings and conclusions for policy consistency and customer interests.

Q. Does this complete your pre-filed direct testimony?

A. Yes.

GEORGE E. WENNERLYN

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CAREER SUMMARY

ELECTRIC AND NATURAL GAS UTILITY AND CONSULTING EXECUTIVE with over 35 years of progressive experience in sales/service to the residential, commercial, industrial, institutional, and utility markets

PROFESSIONAL EXPERIENCE

SELECT ENERGY CONSULTING, LLC, Middleton, WI (1996 to present)

A consulting firm formed to work with commercial, institutional, and industrial clients facing the challenges of deregulation in the natural gas markets and seeking new answers in the midst of on going change.

Principal and Owner

Applies first hand knowledge of natural gas supply planning, pricing and the use of hedging techniques, contract development, cost-benefit analysis, and the state and federal regulatory process. Serves as an expert witness to attorneys seeking advice and direction in the areas of natural gas (utility and market rates, gas supply acquisition, pipeline transportation, gas industry regulation and deregulation, pipeline bypass).

A&C ENERCOM CONSULTANTS, INC., Madison, WI (1994 to 1996)

A&C is the nation's largest supplier of energy related services to the electric and gas utility industry. Providing products and services to over 300 utilities and their customers, the company specializes in the areas of utility market program development, energy conservation services, end-use pricing, and project financing.

Director of Operations and Business Consultant

Responsible for the development of new electric and natural gas sales initiatives within the Midwest, working with participating utilities, providing turnkey (Paid From Savings) services to commercial, industrial, and institutional customers. Consulting included providing advice and direction to electric and gas utilities on customer service programs.

WISCONSIN POWER AND LIGHT COMPANY, Madison, WI (1968 to 1994)

WP&L is a major Wisconsin utility providing electric power, natural gas and water service to 330,000 customers in the south central portion of the state, with total revenues of $680 million.

Director of Gas Supply and Gas Pricing (1992 to 1994)

Directed natural gas supply acquisition and customer pricing functions within a rapidly changing marketplace.

Responsible for the purchase of a $65 million gas portfolio annually, achieving the lowest gas acquisition costs among the state utilities served by the major incoming pipeline.
Implemented a new telemeter system with reliability and accuracy objectives achieved on schedule.

Increased industrial gas sales to capture 45% share of the transportation market.

Director of Rate Design and Gas Supply (1989 to 1992)

Responsible for the forecasting of market sales and the pricing of electric, natural gas and water services.

Responsible for the development of demand-side planning analysis for the electric and gas utility.

Implemented a $10 million electric direct load control program on schedule, meeting all sales goals.

Director of Gas Supply and Gas Engineering (1987 to 1989)

Constructed a $5 million pipeline project both on budget and on schedule.

Realigned pre-existing pipeline service contracts, reducing annual contract costs by $6 million, which enhanced the company's competitiveness via alternate source options.

Reduced annual gas costs by 20%

Regional Manager (1981 to 1987)

Managed five district operation centers, comprised of 350 salaried and hourly union represented employees serving 160,000 customers.

Launched the formal process of developing account strategies for the company's major industrial and wholesale customers.

Redirected the field organization's approach to serving its customers through the adoption of service oriented, customer focused principles.

Developed a company wide reporting system to measure cost center performance.

Division Manager (1976 to 1981)

Spearheaded the local public relations effort to construct a major electric generating facility in the area. Appeared before the news media (radio, newspaper, television), community groups, civic leaders, and government/political officials.

Other Positions (1968 to 1976)

Held a number of positions of increasing responsibility including, Accounting and Customer Relations Supervisor, Local Manager, and Manager at various field office locations.

EDUCATION

B.S., Business Administration - University of Minnesota
Post-Graduate Studies in Business and Sales

INDUSTRY RELATED PARTICIPATION

Madison Area Business Consultants
Past-Chairperson for the Wisconsin Distributors Group
Past-Edison Electric Institute Economics Committee
Past-Vice President of the Association of Industry & Manufacturers

Testimony

Wennerlyn, since founding Select Energy Consulting, LLC in 1996, has testified in the following proceedings:

Submitted To:	Subject	Docket No.	Date
Public Utilities Commission of Nevada	Nevada Power Company application to adjust Base Tariff Energy Rate and DEAA case to collect deferred costs (for Bureau of Consumer Protection)	06-01016	2006
Public Utilities Commission of Nevada	Sierra Pacific Power Company application to adjust Base Tariff Energy Rate and DEAA case to collect deferred costs (for Bureau of Consumer Protection)	05-12001	2006
Wisconsin Public Service Commission	WE Energies rate case, natural gas rate design (for Select Energy Consulting, LLC clients)	05-UR-102	2005
Public Utilities Commission of Nevada	Review Sierra Pacific Power Company and Nevada Power Company Energy Supply Plans Update (for Bureau of Consumer Protection)	05-9016 and 05-9017	2005
Public Utilities Commission of Nevada	Review Nevada Power Company's Energy Supply Plan (for Bureau of Consumer Protection)	04-9004	2004
Public Utilities Commission of Nevada	Review Sierra Pacific Power Company's Energy Supply Plan (for Bureau of Consumer Protection)	04-7004	2004
Public Utilities Commission of Nevada	Prudence of Southwest Gas PGA costs, purchase practices (for the PUCN)	03-12012	2004
Wisconsin Public Service Commission	Wisconsin Public Service Corporation Rate case – rate	6690-UR-116	2004

	design issues		
Wisconsin Public Service Commission	Wisconsin Public Service Corporation Rate case – rate design issues	6690-UR-115	2003
Wisconsin Public Service Commission	Madison Gas & Electric Rate case – rate design issues	3270-UR-112	2003
Wisconsin Public Service Commission	Wisconsin Electric Power Company rate case, fuel filing – risk management	6630-UR-111	2003
Wisconsin Public Service Commission	Madison Gas & Electric Rate case – rate design issues	3270-UR-111	2002
Wisconsin Public Service Commission	Wisconsin Public Service Corporation Rate case – rate design issues	6690-UR-113	2001
Wisconsin Public Service Commission	Wisconsin Public Service Corporation Rate case – rate design issues	6690-UR-112	2000
Wisconsin Public Service Commission	Wisconsin Electric Power Company rate case, rate design	6630-UR-111	2000
Wisconsin Public Service Commission	Madison Gas & Electric Rate case – rate design issues	3270-UR-110	2000
Wisconsin Public Service Commission	Madison Gas & Electric Rate case – rate design issues	3270-UR-110	2000

UNS Gas - Monthly WACOG Calculation

Source: from Monthly filed PGA reports and Data Requests BG 3.1 through BG 3.5, and BG 4.1, 4.2, 4.11, and 4.13
Note: "Retail" here means the gas cost for a retail customer, at the point of purchase. It does not signify cost at either the city-gate or the burnertip.

		From PGA monthly reports			From Supply Basin Mix Report:			Basin Market Price (first of the month) Comparisons to UNS Retail Price:						Results:		
Month	Year	Retail Commodity Only Gas Cost	Retail Purchase Volumes Dths	Retail Commodity Only $/Dth	FOM SanJuan Volumes	FOM Permian Volumes	FOM Waha Volumes	San Juan FOM Price	Permian FOM Price	Waha FOM Price	Market WACOG FOM Price (Basin weighted)	Variance Retail above Market ($ per dth)	Variance Retail above Market (%)	Monthly Variance Retail Commodity above Market	To-date Retail Commodity above Market Commodity	Annual To-date Retail Commodity above Market Commodity
Sep	2003	$ 1,685,734	337,804	$ 4.99	[redacted]	[redacted]	[redacted]	$ 4.44	$ 4.77	$ -	[redacted]	$ 0.55	12.4%	$ 185,884	$ 185,884	$ 185,884
Oct	2003	$ 2,383,376	476,796	$ 5.00	[redacted]	[redacted]	[redacted]	$ 3.95	$ 4.14	$ -	[redacted]	$ 1.05	26.6%	$ 500,032	$ 685,916	$ 685,916
Nov	2003	$ 6,160,289	1,352,365	$ 4.56	[redacted]	[redacted]	[redacted]	$ 3.96	$ 4.07	$ -	[redacted]	$ 0.60	15.0%	$ 804,924	$ 1,490,840	$ 1,490,840
Dec	2003	$ 8,691,238	1,789,037	$ 4.86	[redacted]	[redacted]	[redacted]	$ 4.23	$ 4.36	$ -	[redacted]	$ 0.63	14.8%	$ 1,123,611	$ 2,614,451	$ 2,614,451
Jan	2004	$ 10,304,726	1,933,619	$ 5.33	[redacted]	[redacted]	[redacted]	$ 5.13	$ 5.40	$ -	[redacted]	$ 0.20	3.9%	$ 382,241	$ 2,996,692	$ 382,241
Feb	2004	$ 9,375,716	1,812,765	$ 5.17	[redacted]	[redacted]	[redacted]	$ 5.01	$ 5.13	$ -	[redacted]	$ 0.16	3.2%	$ 292,834	$ 3,289,526	$ 675,074
Mar	2004	$ 4,609,917	914,202	$ 5.04	[redacted]	[redacted]	[redacted]	$ 4.40	$ 4.53	$ -	[redacted]	$ 0.64	14.6%	$ 587,428	$ 3,876,954	$ 1,262,503
Apr	2004	$ 3,764,404	798,592	$ 4.71	[redacted]	[redacted]	[redacted]	$ 4.46	$ 4.67	$ -	[redacted]	$ 0.25	5.7%	$ 202,637	$ 4,079,590	$ 1,465,139
May	2004	$ 2,275,120	451,737	$ 5.04	[redacted]	[redacted]	[redacted]	$ 5.06	$ 5.32	$ -	[redacted]	$ (0.02)	-0.5%	$ (10,669)	$ 4,068,921	$ 1,454,470
Jun	2004	$ 1,972,107	365,752	$ 5.39	[redacted]	[redacted]	[redacted]	$ 5.71	$ 6.19	$ -	[redacted]	$ (0.32)	-5.6%	$ (116,337)	$ 3,952,584	$ 1,338,133
Jul	2004	$ 1,884,910	348,413	$ 5.41	[redacted]	[redacted]	[redacted]	$ 5.49	$ 5.94	$ -	[redacted]	$ (0.08)	-1.5%	$ (27,877)	$ 3,924,707	$ 1,310,256
Aug	2004	$ 1,920,143	350,578	$ 5.48	[redacted]	[redacted]	[redacted]	$ 5.39	$ 5.68	$ -	[redacted]	$ 0.09	1.6%	$ 30,528	$ 3,955,234	$ 1,340,783
Sep	2004	$ 1,986,737	394,000	$ 5.04	[redacted]	[redacted]	[redacted]	$ 4.56	$ 4.72	$ -	[redacted]	$ 0.48	10.6%	$ 190,097	$ 4,145,331	$ 1,530,880
Oct	2004	$ 3,811,869	773,184	$ 4.93	[redacted]	[redacted]	[redacted]	$ 4.47	$ 4.59	$ 5.37	[redacted]	$ 0.44	9.9%	$ 342,743	$ 4,488,075	$ 1,873,623
Nov	2004	$ 9,760,850	1,502,184	$ 6.50	[redacted]	[redacted]	[redacted]	$ 6.90	$ 6.94	$ 6.94	[redacted]	$ (0.41)	-5.9%	$ (611,268)	$ 3,876,807	$ 1,262,356
Dec	2004	$ 11,444,743	1,937,883	$ 5.91	[redacted]	[redacted]	[redacted]	$ 5.95	$ 6.17	$ -	[redacted]	$ (0.05)	-0.9%	$ (105,005)	$ 3,771,802	$ 1,157,351
Jan	2005	$ 10,709,176	1,847,191	$ 5.80	[redacted]	[redacted]	[redacted]	$ 5.67	$ 5.58	$ -	[redacted]	$ 0.13	2.3%	$ 241,044	$ 4,012,846	$ 241,044
Feb	2005	$ 8,756,758	1,531,933	$ 5.72	[redacted]	[redacted]	[redacted]	$ 5.43	$ 5.53	$ -	[redacted]	$ 0.29	5.3%	$ 437,760	$ 4,450,606	$ 678,805
Mar	2005	$ 7,808,477	1,403,641	$ 5.56	[redacted]	[redacted]	[redacted]	$ 5.21	$ 5.54	$ -	[redacted]	$ 0.35	6.7%	$ 491,352	$ 4,941,958	$ 1,170,157
Apr	2005	$ 5,178,267	890,909	$ 5.81	[redacted]	[redacted]	[redacted]	$ 6.21	$ 6.37	$ -	[redacted]	$ (0.40)	-6.4%	$ (354,278)	$ 4,587,681	$ 815,879
May	2005	$ 3,110,406	541,991	$ 5.74	[redacted]	[redacted]	[redacted]	$ 6.30	$ 6.27	$ -	[redacted]	$ (0.56)	-8.9%	$ (304,137)	$ 4,283,543	$ 511,741
Jun	2005	$ 2,150,224	394,206	$ 5.45	[redacted]	[redacted]	[redacted]	$ 5.38	$ 5.66	$ -	[redacted]	$ 0.07	1.4%	$ 29,396	$ 4,312,939	$ 541,137
Jul	2005	$ 2,063,377	350,085	$ 5.89	[redacted]	[redacted]	[redacted]	$ 6.05	$ 6.71	$ -	[redacted]	$ (0.16)	-2.6%	$ (54,637)	$ 4,258,302	$ 486,500
Aug	2005	$ 2,376,435	361,674	$ 6.57	[redacted]	[redacted]	[redacted]	$ 5.97	$ 6.76	$ -	[redacted]	$ 0.60	10.1%	$ 217,241	$ 4,475,543	$ 703,741
Sep	2005	$ 2,820,039	384,556	$ 7.33	[redacted]	[redacted]	[redacted]	$ 8.03	$ 8.61	$ -	[redacted]	$ (0.70)	-8.7%	$ (268,001)	$ 4,207,542	$ 435,740
Oct	2005	$ 5,202,655	632,750	$ 8.22	[redacted]	[redacted]	[redacted]	$ 9.52	$ 9.80	$ 10.11	[redacted]	$ (1.31)	-13.7%	$ (826,205)	$ 3,381,337	$ (390,465)
Nov	2005	$ 8,879,039	1,171,200	$ 7.58	[redacted]	[redacted]	[redacted]	$ 10.82	$ 10.75	$ 11.40	[redacted]	$ (3.25)	-30.0%	$ (3,803,054)	$ (421,717)	$ (4,193,518)
Dec	2005	$ 15,073,197	1,843,808	$ 8.18	[redacted]	[redacted]	[redacted]	$ 8.11	$ 8.45	$ -	[redacted]	$ 0.06	0.7%	$ 105,237	$ (316,480)	$ (4,088,282)

	Commodity cost	% variance
Total for entire period	$ 156,159,929	-0.2%
Year 2005	$ 74,128,050	-5.5%
Year 2004	$ 63,111,242	1.8%
Balance 2003	$ 18,920,637	13.8%

Variance	
$ (316,480)	Total for entire period
$ (4,088,282)	Year 2005
$ 1,157,351	Year 2004
$ 2,614,451	Balance 2003

Note:
Negative number is below market or less than
Positive number is above market or more than

UNS Gas, Inc. 36-Month Ranking Analysis
Compares the High, Low, and Actual Purchase Price (NYMEX Equivalent)
Covers the period of September 2004 through December 2005

Delivery Month	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Total
High price purchase value									[redacted]				
Low price purchase value													
Actual purchase value													
Ranking	no review	no review	no review	no review	no review	no review	no review	no review	70%	70%	31%	60%	55%
Volume Delivered									[redacted]				
36-Month High Price									[redacted]				
36-Month Low Price													
Average Price Actual													

Delivery Month	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total
High price purchase value	[redacted]												
Low price purchase value													
Actual purchase value													
Ranking	56%	56%	39%	80%	81%	66%	64%	75%	76%	76%	55%	50%	56%
Volume Delivered	[redacted]												
36-Month High Price	[redacted]												
36-Month Low Price													
Average Price Actual													

Delivery Month	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total
High price purchase value	[redacted]												
Low price purchase value													
Actual purchase value													
Ranking	50%	50%	51%	52%	48%	47%	46%	38%	25%	17%	17%	25%	37%
Volume Delivered	[redacted]												
36-Month High Price	[redacted]												
36-Month Low Price													
Average Price Actual													

UNS Gas, Inc. 36-Month Ranking Analysis
Compares the High, Low, and Actual Purchase Price (NYMEX Equivalent)
Covers the period of September 2004 through December 2005

Annual Results

Delivery Year	2003* (note: partial year)	2004	2005	Total
High price purchase value Low price purchase value Actual purchase value	[redacted]			
Ranking	55%	56%	37%	46%
Volume Delivered	[redacted]			
36-Month High Price 36-Month Low Price Average Price Actual	[redacted]			